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Microscale Biomass Generation for Continuous Power Supply to Remote Customers

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MICRO-SCALE BIOMASS GENERATION FOR CONTINUOUS POWER SUPPLY TO REMOTE CUSTOMERS

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"By 2030, the electric utility industry in the US will need to make a total infrastructure investment of $1.5 trillion to $2.0 trillion. The combined investment in new transmission and distribution during this period will total about $880 billion, including $298 billion for transmission and $582 billion for distribution."

Transforming America's Power Industry: The Investment Challenge 2010-2030

The Brattle Group (for: The Edison Foundation), November 2008

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"High levels of investment are likely to be needed in the UK to secure energy supplies and meet carbon targets – up to £200 billion may be required over the next 10-15 years. This includes up to £40 billion for transmission and distribution investments."

Project Discovery: Energy Market Scenarios

Ofgem UK (Office of Gas and Electricity Markets), October 200

Abstract

Remotely located and sparsely populated areas often do not have access to an efficient grid-connection for electricity supply. However, plenty of biomass is normally available in such areas. Instead of employing island solutions such as small diesel generators or large battery stacks for power provision, a flexibly operating micro-scale biomass power plant using locally available and renewable feedstock is not only an efficient way of providing those areas with competitive and reliable electricity, but also a step towards energy self-sufficiency for a large share of areas worldwide, and towards mitigating the looming high costs of grid infrastructure upgrading and extension.

A novel power plant design combining thermochemical and biochemical biomass treatment was developed in this research. This system consists of a small-scale gasifier and an anaerobic digester unit, both coupled to a gas storage system and a microturbine as the generation unit. This design is suitable to continuously provide reliable electricity and accommodate fluctuating residential power demand, and it can be scaled to a level of around 100kW$_e$, which is a fitting size for a group of residential customers, such as in a remote village.

The project covers a review of available technology; the choice of suitable technology for such a plant and the design of the system; the set up of a detailed plant model in chemical engineering software; extensive simulation studies on the basis of load profiles to evaluate and optimise operation; and feedstock sourcing, efficiency and economic analyses.

It will be shown that such a system is a feasible and economic solution for remote power supply, and that it can overcome many of the current obstacles of electrifying rural regions.

Acknowledgement

The author would like to express his sincere gratitude to all those without whom this research and its outcome would not have been accomplished.

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Nomenclature and Abbreviations

A	Surface Area [m^2]
A_c, A_f	Current / Future Amount of Money [£, €]
AD	Anaerobic Digestion
AFR	Air Fuel Ratio [%]
C	Carbon
C_2H_6	Ethane
c_i	Specific Heat Capacity (Substance *i*) [J/kg·K]
C_n	Cost Stream (year *n*) [£, €]
CH_4	Methane
CHP	Combined Heat & Power
CO	Carbon Monoxide
CO_2	Carbon Dioxide
cv	Calorific Value [MJ/kg, MJ/m^3]
D_C	Calendar Days (Case *C*) [-]
DM	Dry Matter Content [%]
E_n	Energy (System Point *n*) [J]
$\dot{E}_n$	Energy Flow (System Point *n*) [J/s]
EFGT	Externally Fired Gas Turbine
eqn.	Equation
$\dot{\eta}$	Part-Load Efficiency [%]
η_c	Carnot Efficiency [%]
η_{is}	Isentropic Efficiency [%]
η_n	Efficiency (System point *n*) [%]
EtOH	Ethanol
FC	Fixed Carbon Content [%]
$F_n(k)$	Fulfilment Factor (Criterion *n*, Alternative *k*) [-]
$FF(k)$	Fulfilment Function (Alternative *k*) [-]
G, ΔG	Gibb's Free Energy, Difference in Gibb's Free Energy [J]
ΔG_f	Standard Gibb's Free Energy of Formation [J/mol]
G_n	Gibb's Free Energy (State *n*) [J]
GE	Gas Engine
H	Hydrogen
H	Enthalpy [J]
h	Height [m]
h_n	Specific Enthalpy (State *n*) [J/kg]
H_2	Hydrogen, molecular
H_2O	Water
H_2S	Hydrogen Sulphide
HHV	Higher Heating Value [MJ/kg, MJ/m^3]
HRT	Hydraulic Retention Time [d]
ICE	Internal Combustion Engine
K	Potassium
LHV	Lower Heating Value [MJ/kg, MJ/m^3]
LCA	Life Cycle Analysis
λ	Ratio [-], Load Factor [%]
m_i	Mass (Substance *i*) [kg]
mf_i	Mass Fraction (Substance *i*) [%]
mc	Moisture Content [%]
MCDA	Multi-Criteria Decision Analysis

MCDM	Multi-Criteria Decision Making
MoS	Margin of Safety [%]
MSW	Municipal Solid Waste
N	Nitrogen
n	Amount of Substance [mol], Number of years [-]
$\dot{N}$	Load Factor [%]
N_2	Nitrogen, molecular
N_2O	Nitrous Oxide
NO	Nitrogen Monoxide
NO_x	Nitrogen Oxides
NPV	Net Present Value [£, €]
O	Oxygen
O_2	Oxygen, molecular
OM	Organic Matter Content [%]
O&M	Operation & Maintenance
P	Phosphorous
P_n	Power (System Point n) [J/s, W]
$\overline{P}_n$	Average Power (System Point n) [J/s, W]
Q_n	Heat (System Point n) [J]
r	Discount rate [%], Radius [m]
R_n	Revenue Stream (year n) [£, €]
ρ_i	Density (Substance i) [kg/m^3]
S	Sulphur
S	Entropy [J/K]
SO_2	Sulphur Dioxide
SRC	Short Rotation Coppice
SWOT	Strengths, Weaknesses, Opportunities, Threats
σ	Storage ratio [%]
T , t	Temperature [°C, K]
t , Δt	Time, Period of Operation [s]
Δt_n	Temperature Difference (System Point n) [K]
Δt_0 , Δt_L	HTemperature Difference [K]
ΔT_{LM}	Logarithmic Mean Temperature Difference [K]
T_{amb}	Ambient Temperature [°C, K]
T_C , T_H	Cold Side, Hot Side Temperature [°C, K]
T_d	Digester Temperature [°C, K]
TS	Total Solids Content [%]
U	Overall Heat Transfer Coefficient [W/m^2·K]
V_i	Volume (Substance i) [m^3]
$\dot{V}_i$	Volume Flow Rate (Substance i) [m^3/s]
VM	Volatile Matter Content [%]
VS	Volatile Solids Content [%]
W_n	Weighing Factor (Criterion n) [-], Work (System Point n) [J]
$\dot{W}_n$	Power (System Point n) [J/s, W]

1 Introduction and Background

The current power system in the UK has its origins in 1882 when Edison set up the first ‘power plant’, the Holborn Viaduct Generating Station in London with 60kW generation capacity, to power consumers through 100V direct current cabling [1, 2]. Based on this development of power equipment, the following years saw a huge increase in the number of power stations that were set up in the UK to serve towns or large customers as independent power sources; and similar developments occurred in most other developed countries [1, 2].

In 1926 this plurality of independent power generators in the UK was required by law to be interconnected through a high-voltage transmission grid, and shortly after World War II it was decided to nationalise the UK power system, and to split it into two parts: one centralised group consisting of the generators and the transmission network, and one group of several regional distribution networks that connect to the single customers. These two laws can thus be seen as the beginning of the grid system on which the UK, the US and many other European power systems are based until this very day [1].

Once this system was developed, it was very convenient to respond to the continued growth of demand for power by increasing the grid and spreading it out even further, and by increasing the size of central power stations that generate the power to meet this demand. Figure 1-1 [2] shows this development for the US by depicting the trend of increasing power plant capacities over the decades, and a similar activity again was seen worldwide.

Evidently, the larger those power stations became, the more fuel they needed on a continuous basis. Therefore, most large new power plants were built adjacent to transport links such as harbours and rivers, or close to their fuel sources, which were mainly water and coal, later joined by oil and gas. This however meant that whilst at the beginning, power stations were built locally and situated close to the demand they satisfied, with increasing size they were located further and further away from their customers; for example, in 1980 the average power station in the US delivered its output over an average distance of 343km of grid network in order to reach its customers [2]. This in turn made the ongoing extension of the grid more and more important [1, 2].

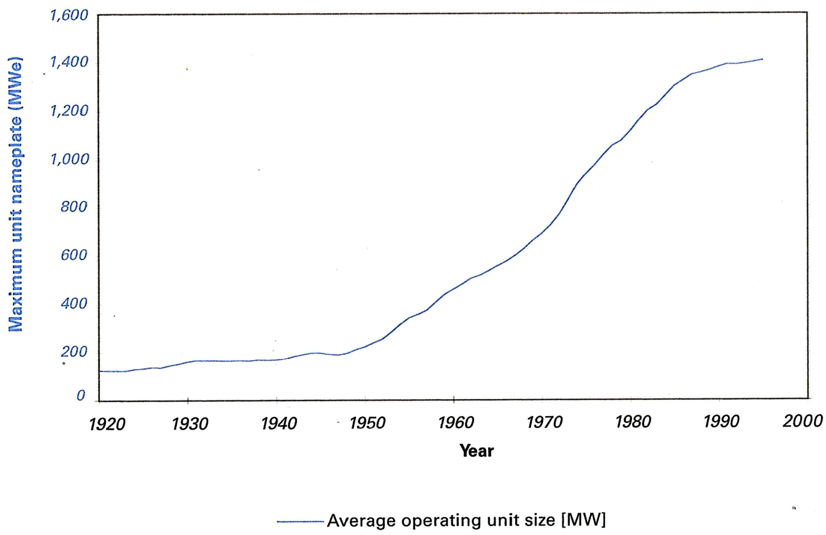

Figure 1-1: Growth of US Power Station Capacity from 1920-1995 (Source: adapted from [2]).

The result of this development is that the current UK power system, and that of most other developed countries, is heavily centralised. Large scale power plants, often located very far away from the centres of power demand, satisfy a high proportion of the demand, and the power is transported to the customers through an extensive high-voltage transmission grid and lower-voltage distribution grids. This is shown impressively by Figure 1-2 [3] which depicts the extent of the current transmission grid and the largest power stations in Great Britain, and through Table 1-I [4] which lists the 20 largest UK power stations and their power capacity as a percentage of the total UK network capacity. Despite constituting only 6% of the number of all power stations with at least 1MW of capacity, those twenty stations alone cater for nearly 48% of the total UK capacity [4].

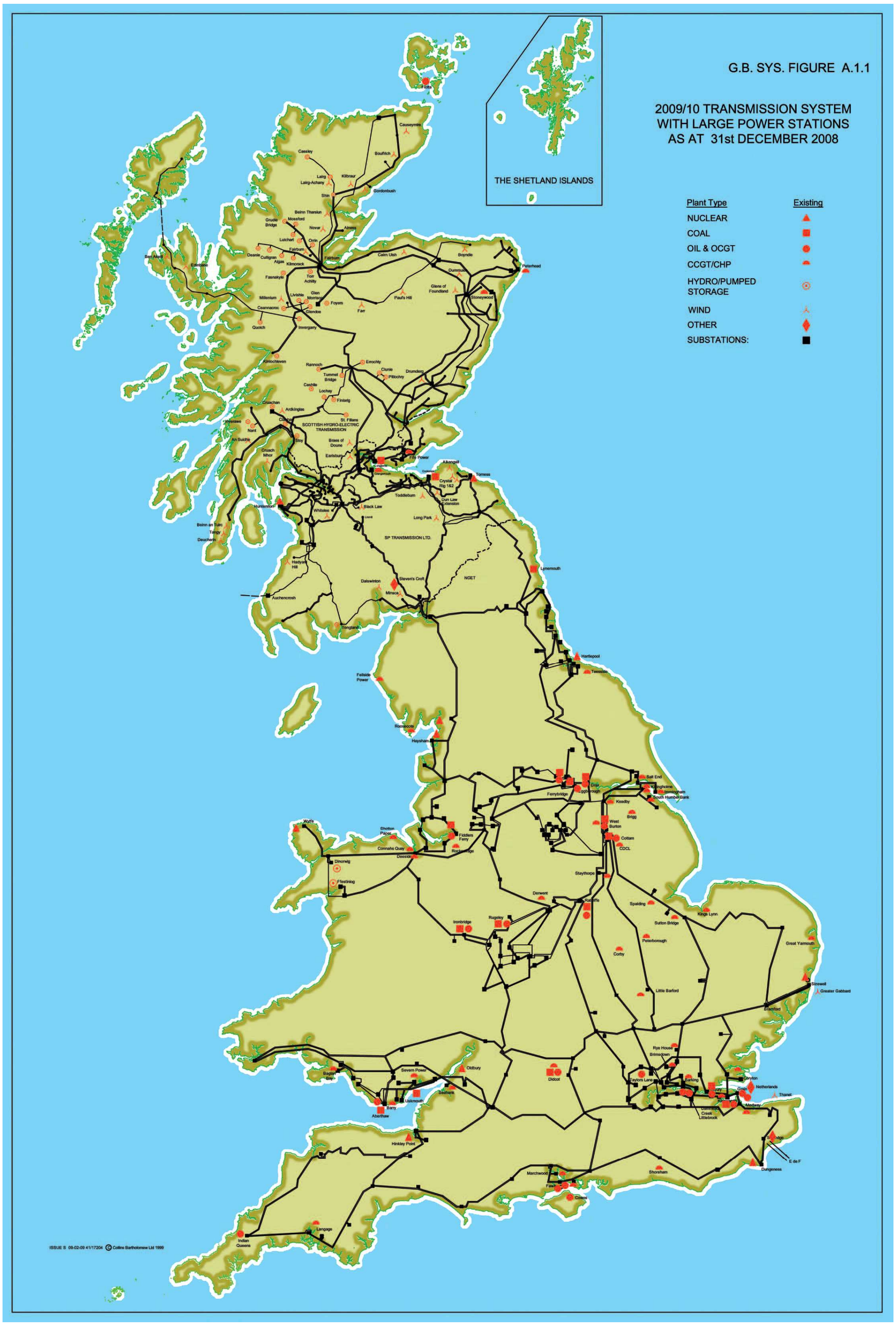

Figure 1-2: Transmission Grid and Largest Power Stations in Great Britain (Source: [3]).

Table 1-I: List of the Twenty Largest UK Power Stations and their Rating (Source: [4]).

Station Name	Type	Plant Capacity [MW]	% of Total UK Capacity
Drax[1]	coal	3,870	5.06%
Longannet[3]	coal	2,304	3.01%
West Burton[1]	coal	2,012	2.63%
Cottam[1]	coal	2,008	2.63%
Ratcliffe[1]	coal	2,000	2.62%
Fiddler's Ferry[1]	coal/biomass	1,980	2.59%
Eggborough[1]	coal	1,960	2.56%
Ferrybridge C[1]	coal/biomass	1,960	2.56%
Didcot A[1]	coal/gas	1,958	2.56%
Kingsnorth[1]	coal/oil	1,940	2.54%
Teesside[1]	CCGT	1,875	2.45%
Dinorwig[2]	pumped storage	1,728	2.26%
Aberthaw B[2]	coal	1,586	2.07%
Peterhead[3]	gas/oil	1,540	2.01%
Didcot B[1]	CCGT	1,390	1.82%
Connahs Quay[2]	CCGT	1,380	1.81%
Littlebrook D[1]	oil	1,370	1.79%
Grain[1]	oil	1,300	1.70%
South Humber[1]	CCGT	1,285	1.68%
Heysham[2]	nuclear	1,240	1.62%

Notes: Plant Location: [1] – England; [2] – Wales; [3] – Scotland;
Total UK Capacity 2008: 76,450 MW; CCGT – Combined Cycle Gas Turbine Plant

This centralised top-down system, where power is supposed to only flow from the generation plants at the top through the transmission and distribution systems to the customers at the bottom [5], despite having been set up decades ago, has proven to provide reliable and relatively cheap power to customers in the UK and worldwide.

However, the current power system and its infrastructure are ageing, and tremendous investments will be necessary in the next decades for infrastructure replacement, modernisation and upgrading, and for continued extension of the grid network. Even though the exact costs are uncertain, the respective cost forecasts for the UK (£40 billion in the next 10-15 years) and the US ($880 billion by 2030) as mentioned in the citations at the beginning of this thesis indicate the sheer scale of the looming investments necessary to continue providing current reliability levels of power generation and supply, and the current level of power accessibility.

In addition, it becomes increasingly difficult to source sufficient amounts of cheap fuel for the power plants currently available, which are mainly fossil-fuelled [3, 4]. Figure 1-3 [4] shows the long-term trend of coal, gas and oil prices in the UK, and there is no indication that this trend reverses soon.

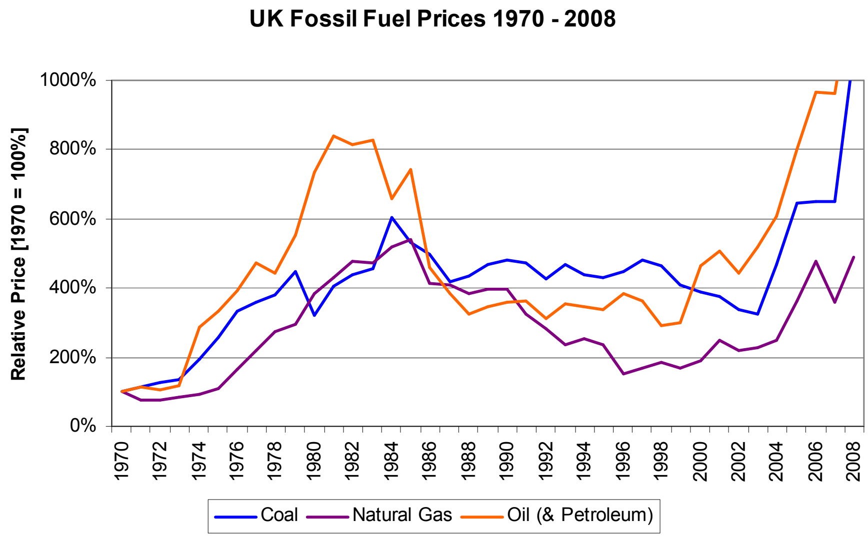

Figure 1-3: Long-Term Historical Coal, Gas and Oil Prices in the UK (Source: [4]).

Furthermore, new power generation technology that starts penetrating the network, such as wind, solar or tidal/wave power, will bring further challenges to the network due to the intermittency of those power generators [3, 5].

This last consideration introduces another crucial factor of current power systems: the demand for power, similar to that of other 'commodities' such as water, oil, gas etc., is not constant but variable, especially the demand of residential customers. This means that the amount of power consumed by all customers on the grid varies over the course of the day and depends on numerous parameters, such as time, season, temperature etc. [5]. Figure 1-4 [3] shows this variation of the daily total demand, or load, of the transmission network in Great Britain.

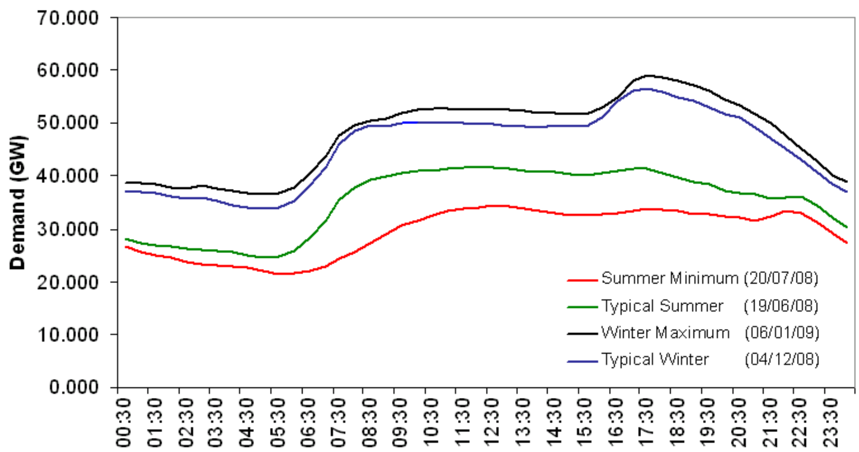

Figure 1-4: Daily Load Profiles of the Transmission Grid in Great Britain (Source: [3]).

However, unlike other commodities, power cannot be stored easily in large quantities to level out the demand; instead, it is necessary to continuously match demand through generation, which means that at each instance of time total generation needs to equal total demand in the network [3]. This was another main reason for setting up a national grid system that interconnects all customers and all generators: the more customers and generators are connected to each other, the easier it becomes to maintain a stable power supply. Generators can operate synchronous with each other, which makes it easier to respond to fluctuations in demand or to cushion the outage of a single generator [5]. Furthermore, the demand also becomes easier to predict when more customers are interconnected (see chapter 7).

In order to match demand with generation, a number of large base load plants are scheduled to operate continuously, 24 hours a day 7 days a week, to satisfy the constant base load demand that can be seen in Figure 1-4. Those plants are mainly large nuclear or coal fired steam plants whose output cannot be adjusted easily [6]. In addition, some relatively flexible peak load plants were developed to level out demand and supply on short notice. Those (mainly gas turbine or pump hydro) plants can be adjusted within time frames of two to twenty minutes in order to respond to demand changes [6].

This design however was again based on the assumption that power only flows from the centralised (base or peak load) power stations to the customers. With more and more intermittent and smaller generators being connected to the grid, not only demand but also generation starts to become a variable value that needs to be forecasted and that depends on the circumstances of the environment, such as wind speed or solar radiation levels. This in turn means that the grid system increasingly has to match a variable demand with intermittent and irregular generation, which given the lack of power storage makes the process more and more cumbersome [3].

Whilst those are some of the challenges that the current power network faces in the UK and in other developed countries, most developing countries still lack such infrastructure to begin with, which explains why large shares of the population are still 'off-grid'. Even though access to reliable power is relatively cheap and very convenient for most customers in the developed world, around 2 billion people and thus one third of the world population is still deemed to not have access to power at all, apart from using expensive batteries with low lifetimes or small diesel generators that only operate for a couple of hours each day and that do not necessarily follow the demand [2, 7, 8].

Furthermore, rural areas which are only sparsely populated are costly and difficult to connect to an existing grid network even in developed countries, but a significant share of the population still lives there. For example, around 19% of the population in England and around 36% of the Welsh population live in rural areas [9]. Figure 1-5 [10] shows the distribution grid network of the North West of England, and it can be seen that an extensive network needs to be maintained in order to reach (relatively few) remote customers in the north of the network, when compared to the more urban regions in the south.

At this point it becomes apparent that the economics of such an investment case are unlikely to be very promising, as lots of equipment serves a relatively small load, which means that the equipment utilisation factor will be low [2, 5]. So even though those customers may only consume a relatively small proportion of the total power in a network, supplying them with power can result in prohibitively high overall costs for the network operator [2, 5]. This in turn means that either all network customers have to pay a share of those high connection costs irrespective of their location, or only the remote customers have to shoulder the expenses. Since simply denying power access to those customers cannot be a reasonable solution, the former alternative is the one usually chosen, at least in developed countries [2, 5]. This however results in higher infrastructure costs for all customers, even for those in unaffected urban areas.

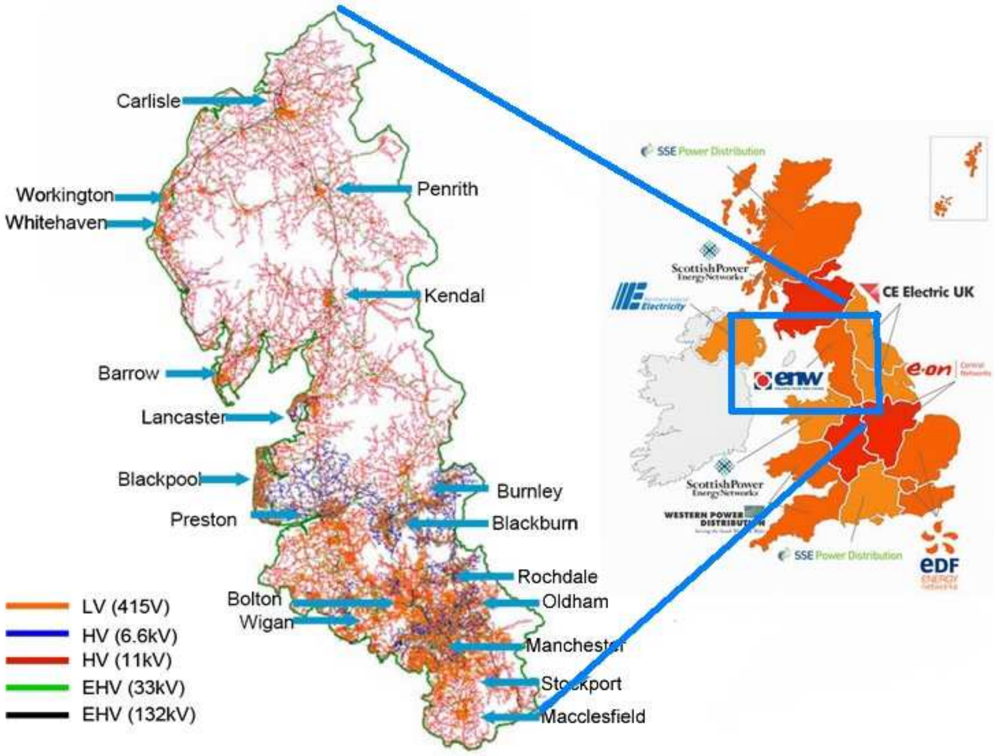

Figure 1-5: North West England Distribution Grid Network (Source: [10]).

To summarise the aforementioned problems which current power systems will have to face in the next decades, four main challenges can be stated as follows:

I. Looming High Infrastructure Costs

II. Spiralling Fossil Fuel Costs

III. Matching Variable Demand with Increasingly Intermittent Generation

IV. Prohibitive Costs of Grid Extension into Remote Areas

The resulting question thus becomes:

"How can these challenges be tackled?"

Increasing the share of renewable generation can mitigate rising fuel costs and increase the independency of power consuming countries from fuel producing countries, and is thus often proclaimed as the obvious solution. Most current generation in the UK is based on fossil fuels, however an ever increasing share of this fuel needs to be imported [4], which not only results in vulnerability of the economy with regards to rising fuel costs, but can also lead to severe issues regarding security of supply[1]. In either way, fossil fuels are finite resources which can lead to difficulties of provisioning, whilst in contrast, renewable power sources can by definition be harvested continuously and would thus increase self-sufficiency if available within the country.

However, as mentioned above, the main renewable power sources that are currently deployed (wind, solar, tidal) are intermittent and would thus require a significant amount of control to balance demand and generation once they penetrate the current network to a high extent [3, 12]. In addition, there are still severe cost disadvantages of renewable power generation as the technologies are relatively new and try to compete with conventional power generation technology that has been developed and deployed for decades [2, 5, 13].

This means that the currently deployed renewable generation only tackles one of the aforementioned challenges (fuel prices), whilst worsening (intermittency) or at least leaving unaffected (infrastructure costs) others.

One renewable source for power generation however has the material advantage of being non-intermittent. Biomass, which refers to all living and dead organic matter and thus includes wood, straw, grasses and vegetables, as well as algae, vegetable waste, or manure (see also chapter 4), is available on a continuous basis and could thus be used as a non-intermittent fuel source for power generation. This means that power generated from biomass becomes predictable and can be adjusted through the amount of biomass fuel used.

Furthermore, the total amount of biomass available is staggeringly high. It is calculated that approximately 200 billion tonnes of biomass exist worldwide,

[1] The difficult and highly emotional topic of 'wars for fuel' [11] should however only be mentioned as a side-note in this project, as it carries the potential to become a topic for extensive research itself.

containing around 25,000-30,000EJ [2] of energy; and that a further 15 billion tonnes containing 2250EJ is added each year through plant growth [14, 15]. The annual biomass growth alone thus exceeds the total world energy consumption of 450EJ by a factor of five [15], and even though it is apparent that not all of this biomass could ever be used for energy purposes, those figures still indicate the tremendous potential of biomass as a power source.

Therefore, a recent surge in the interest of biomass-for-power deployment is noticeable, although this activity is mainly undertaken at large scale due to economic reasons [16], which means that it is tried to simply replace centralised fossil-fuelled power stations with centralised biomass-fuelled power stations. This development however leads to a myriad of problems.

Firstly, large biomass power plants will still need the same grid infrastructure to deliver their power to the customers that large fossil fuel power plants currently use, so the challenge of looming infrastructure costs is not remedied at all.

Secondly, large-scale biomass power plants need very large amounts of biomass fuel on a continuous basis; for example, the world's largest biomass plant with a capacity of 350MW [3], planned for construction in Port Talbot (Wales), will require a wood chip intake of around 350 tonnes per hour [17]. This means that it will be infeasible to source this feedstock locally, which makes both import and transport of the biomass to the plant necessary. This in turn not only increases fuel costs, but also detrimentally affects customers situated along the transport ways and highly questions energy self-sufficiency.

Finally, biomass as a fuel is generally regarded as a renewable power source, since the amount of carbon released during its use roughly equals the amount of carbon the biomass captured during growth [18]. However, this is dependent on the way biomass is produced and handled. Whilst using available waste biomass (e.g. manure, waste wood etc.) for power purposes without doubt results in a replacement of fossil fuel,

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[2] 1EJ is one Exajoule of energy, or 1 x 10^{18}J.

[3] It should be noted that despite being the world's largest biomass power plant, this plant would still only have 10% of the capacity of the largest current power plant in the UK as shown in Table 1-I, and would only be number 66 in this list.

and thus in less carbon being emitted, recent development of large scale biomass plantations has also shown that there are potential threats and drawbacks. The possible impact of biomass plantations on food prices when arable land is switched from grain production to biofuel production, and the deforestation of rainforest for monoculture palm oil plantations [19-21] should be mentioned here as only two examples. Those issues, albeit sometimes being discussed on a very emotional and less factual basis [22], without doubt point towards a possible danger of applying biomass in the wrong, a non-sustainable, way. This is further severed when biomass fuel is transported over long distances between the producer and the consumer, as it has a lower energy density than fossil fuels and thus requires larger volumes to be transported [18].

Therefore, simply replacing current large scale fossil fuel plants by similarly sized biomass plants, albeit tackling the fuel price and the intermittency challenges, cannot overcome all issues mentioned above. It still requires the current level of grid infrastructure and does not remedy the high costs of making power accessible in remote regions, and it might create new problems such as the aforementioned.

Instead, going back several decades in time and trying to overcome the centralisation and grid-dependency of current power supply, and 'reinventing' the decentralised smaller-scale power generators with which the whole power system development initially began, might be more beneficial.

Smaller power plants at, or close to, the point of demand would provide numerous benefits, one of which is the the possibility of supporting or replacing a grid-connection prone to disruption and thus deferring grid infrastructure investments, or rendering them unnecessary altogether. They could also react flexibly to changes in local power demand as they can be set up in a modularised way within short periods of time [2, 5].

Furthermore, conventional transmission and distribution grid systems incur losses of up to 5-10% of the total power transported [2, 4, 5]. Those losses result from the power demand of operating the grid equipment, and from resistive losses caused by the heating effect of power cables when energised. A decentralised power plant close to the local demand could also reduce those losses as power needs to 'travel less' to reach its customers.

In addition, those local power plants could also be operated on fuel sourced locally and possibly on renewable energy carriers to reduce dependency on finite and increasingly expensive fossil fuels, at which point biomass with its high availability would provide an enormous incentive to become more self-sufficient. Finally, it would be significantly easier to connect customers in remote regions to those decentralised power plants instead of trying to extend the conventional power grid.

Therefore, the pathway of decentralised renewable power generation becomes more and more interesting, as it not only manages to address the aforementioned main challenges, but it could also lead to simpler power systems governed by the local demand.

This project will thus undertake to design a micro-scale power plant based on locally available biomass. This plant should be able to flexibly generate sufficient power on an ongoing basis to continuously provide power to a group of remote residential customers, such as in a small village.

Such a small power plant based on renewable energy sources could not only generate power at the point of demand and thus defer or save significant infrastructure investments, but would also use locally sourced fuel, avoiding transport costs and the uncertainty of future fuel prices, and increase energy self-sufficiency. Finally, it would make power accessible to rural areas and could thus benefit rural electrification projects as well as utilities that are faced with very high costs of connecting remotely located new customers to their existing distribution grid.

Upon proving that such a design is feasible under those circumstances, it can then be implied that this system would also be applicable to numerous other settings, such as for larger villages, for less remote regions or for a less variable load, e.g. for industrial customers. All those cases would impose fewer constraints on the system than those described above, so once feasibility for the most critical case is proven in this project, it can then be assumed that the design would also be feasible for all other less critical cases, with few or no alterations necessary.

2 Project Aims and Objectives

The aim of this research is to develop a micro-scale biomass generation plant facilitating continuous power supply to remote residential customers. In order to achieve this aim, and to summarise and clearly lay out the requirements of the project, a set of objectives was developed on the basis of the main challenges as mentioned in the previous chapter. These objectives will be described as follows.

Challenge I: Looming High Infrastructure Costs

The intention of the power plant design in this project is to be deployed in remote regions where access to power is normally either non-existent, prone to disruption, or costly (see also *Challenge IV*). From this follows that the plant should be able to operate without a grid connection, i.e. as a stand-alone system. Should a grid connection be available, then the plant may however be able to use it, as this would constitute a less critical case where the plant would be able to support such an existing grid connection, especially if it is prone to disruption.

In either of those cases, the main benefit would be the possibility to defer or render unnecessary the costly upgrade of existing grid networks if they could be supported or replaced by such an independent power plant. In addition, as decentralised power generation would take over the supply of some local demand, a lower remaining demand would need to be satisfied by the existing central power stations, which means that the need to replace infrastructure would also be remedied to some extent. From this follows that grid-dependency of some areas could be overcome, and that the remaining grid system could be released even if it would still be used in combination with the plant.

Challenge II: Spiralling Fuel Costs

Since the plant is to be operated on biomass, a key objective will be to employ only locally available feedstocks that can be used on a continuous basis without depleting the local resources. Furthermore, their impact on food sources should be minimal in order to ensure that they do not detrimentally affect the local area. This in turn means that transport and import of the feedstock should also be avoided, so only ‘truly sustainable’ feedstock should be used in order to achieve energy self-sufficiency and minimise adverse impacts.

Once the feedstock sources have been chosen, the economic impacts of production, harvest or collection of the feedstock should also be evaluated to ensure that the continuous provision of the feedstock can be achieved without incurring unjustifiable costs or burdens.

Finally, the plant design should be tolerant towards different feedstock sources, since it is likely that it would be operated on varying biomass fuels, depending on the local availability. If all those objectives are met, then it could be concluded that the plant would increase independency from the likely rising fossil fuel prices.

Challenge III: Matching Variable Demand with Intermittent Generation

Even though biomass as such is not an intermittent fuel source and was chosen in this project for this very reason, for the feasibility of operating this system it will be crucial to understand the challenge of levelling out demand and supply. As mentioned in chapter 1, demand varies over the course of the day, but power storage is costly and should thus be avoided for this plant system, if possible. This however only leaves flexible generation to solve the issue of variable demand.

Since the plant is supposed to satisfy the power demand of a group of remote residential customers, one main objective is to understand both the demand patterns and the absolute level of demand to be expected. The scale of this plant should be as small as possible, in order to be neither oversized nor undersized for the local demand it is supposed to supply to. Therefore, a group of around 100 residential customers forming a remote village could be deemed an appropriate minimum scale that needs to be reached. The project therefore needs to investigate the likely level of demand as well as the fluctuations to be expected for such a customer group, and should evaluate whether the plant can feasibly be scaled accordingly. It then needs to be analysed whether the plant can be operated flexibly enough to meet the demand of this customer group in time and without the need of power storage. Finally, it needs to be evaluated whether sufficient feedstock can be sourced for this continuous operation.

Challenge IV: High Grid Connection Costs for Remote Customers

As mentioned under *Challenge I* above, the plant should be designed to be operable without a grid connection, which means that one of the aims of this project is to avoid the high connection costs for remote customers. This would provide utilities facing those costs with an incentive to use this plant design instead. However, from this follows that the economic implications of this system will have to be evaluated, which means that the necessary investments for this plant need to be calculated. Those results should then be compared to the costs of setting up a remote grid connection in order to conclude whether the plant can reach its objective to lower the cost of accessing remote customers.

In addition to understanding the economic implications of the plant, it should also be evaluated whether the plant can be operated sufficiently efficient, i.e. that no fuel feedstock is wasted. This finding should again be compared to the efficiency of conventional grid power supply to understand whether the plant can outperform its alternative, and whether it could thus provide efficiency benefits to the system operator.

Other Aims and Objectives

Besides those requirements resulting from the aforementioned four main challenges, a number of other criteria, which are more standardised for any power plant design, will need to be met. A low-cost design approach is an apparent criterion, which will be covered by the economic analysis.

Furthermore, given the remote location of the plant system and the fact that the plant will likely be the sole power generator for the customers connected to it, a robust design and a high reliability level, i.e. long operation cycles and low maintenance efforts and outage times, will become other crucial factors to evaluate the deployment of this design.

The plant design should also be modular and relatively simple in its set up so that it can be installed without major efforts and be scaled to different demand levels with relative ease.

This set of objectives can and will not only form the basis for judging the results of this project, but it will also be used to structure the research. It defines the project milestones, and the sequence in which they need to be accomplished, which is shown in Figure 2-1.

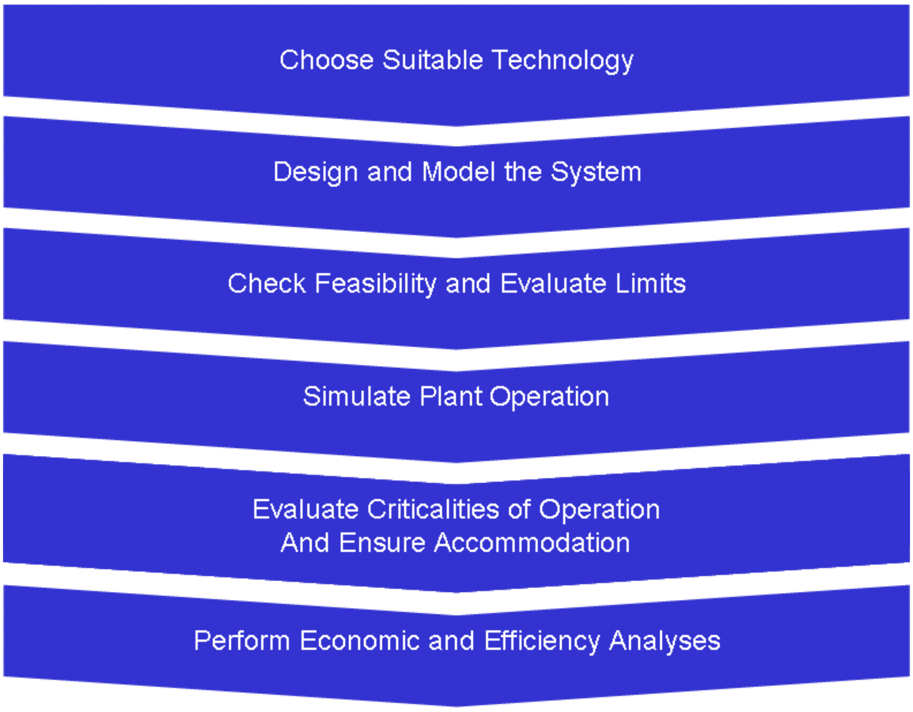

Figure 2-1: Project Milestones.

3 Thesis Structure and Content

The structure of this thesis follows from the milestones shown in Figure 2-1 and from the project objectives as laid out in the previous chapter.

Chapter 1 has provided a brief introduction of the general topic of power generation, transmission and distribution, as well as the different issues of renewable power sources. It has also defined the main challenges of current power systems and how this project should aim to solve them.

On this basis, chapter 2 has then stated the project aims and objectives, and has described the main project targets as well as the milestones within the project.

This current chapter 3 is followed by chapter 4 which contains a detailed discussion and analysis of biomass technology. In the first part, biomass as a fuel feedstock is discussed, and its properties and characteristics are analysed. This is followed by a description of current biomass conversion technologies, and a discussion of biomass-based power generation technology. The final part is a two-step decision making process: after comparing the technologies, a ranking is established, and on this basis it is evaluated which technologies are most suitable for the intended project design and thus will be chosen for the plant.

Chapter 5 describes the combination of the single technologies chosen through the ranking in chapter 4 into one consistent and efficient micro-scale biomass power plant design. This design is then used to set up a simulation model of the plant in chemical process engineering software. The plant model is described in detail, and it is shown that the simulated plant model suitably represents the real plant system.

After the simulation model was set up and justified, chapter 6 provides results of several feasibility studies which were undertaken to check whether the plant system is operable. It also describes a size limitation analysis which covers limitations on the basis of both technological and feedstock sourcing aspects.

Once the model was found feasible and realistic, chapter 7 then covers the main operational simulation and analysis of results. In the first part, residential load profiles are described and evaluated in order to understand which load patterns have to be expected for the plant operation. This is followed by a discussion of the minimum load level necessary to provide a feasible plant operation, and by a brief discussion of obtaining a suitable domestic group and its implications for the load profile data.

The second part of this chapter then provides a detailed load simulation study and describes its results. The plant model is run against the obtained load profiles, and it is shown how the plant performs during one-day and ongoing operation, and whether the plant can provide power continuously. Plant load factors as well as storage sizing issues are addressed, and it is evaluated what fuel storage levels need to be provided in order to enable robust ongoing operation without power storage. This is completed by a discussion of fluctuations in demand that have to be expected when using the plant in off-grid locations, and an evaluation of whether the plant can accommodate these fluctuations.

These simulation studies are followed by chapter 8 which compares the advantages and disadvantages of grid-connected and off-grid operation and evaluates in which modes the plant system can be operated. The second part of this chapter then undertakes an analysis of the transients to be expected under off-grid operation, and discusses whether the plant design can accommodate those transient load changes.

After having proven that the plant is feasible and that it can be operated as required, chapter 9 then concludes this project with an economic and efficiency analysis of the plant. The plant costs for set up, operation, maintenance and feedstock sourcing are evaluated and compared to the revenues. Additionally, soft-money factors such as energy self-sufficiency and environmental impacts are addressed. Those results are then compared to the cost of setting up a conventional grid connection to serve the remote customers. This analysis is followed by a sensitivity analysis which undertakes evaluations of the impact of cost and revenue uncertainties on the plant economics.

Finally, the efficiency of operating the plant is evaluated on both a unit level and a total system level. This efficiency is again compared to the efficiency of providing power through a conventional grid connection.

Chapter 10 then summarises the results and findings of this project, provides the final conclusions and outlines any further work.

The two appendices then conclude this thesis by providing the publications originating from this project and the programming code for the plant model described in chapter 5, respectively.

4 Technology Analysis and Comparison

The first step in developing a micro-scale power plant on the basis of the objectives outlined in chapter 2 has to be the evaluation of plant technology. This includes three main steps, which are shown in Figure 4-1: which feedstock to use; how to convert it into fuel; and how to use this fuel for power generation. This chapter will cover these three main steps and discuss biomass as a feedstock, as well as biomass-based conversion and generation technology. An extensive literature research and market investigation was undertaken in order to evaluate what technology is available and to what extent it can be used for the purposes of this project.

Figure 4-1: From Feedstock Via Conversion and Generation to Heat & Power.

4.1 Biomass Feedstock

Biomass in general can be defined as all living or dead organic matter [18]. This means that it includes all organic substances that have initially been created by converting the atmospheric CO_2 and water into plant material through photosynthesis, a process fuelled by sunlight. This process captures the atmospheric CO_2 and converts it into carbon bound in the carbohydrate molecules of biomass, a process that leads to the energy from sunlight being stored in the chemical bonds of the biomass molecules. When using biomass for power generation, this energy is released and the bound carbon is converted back into CO_2 and water, which means that using biomass as a power source can be defined as carbon neutral, as the carbon is only used in this cycle [18].

Biomass includes plants and plant parts, such as wood, straw, grasses and vegetables, as well as algae. It also includes all dead or processed plant matter, such as dead wood, vegetable waste, bagasse from sugar extraction or pulp liquor from paper production, and finally also digested plant matter, i.e. manure [23]. It is discussed in literature whether to define municipal solid waste (MSW) as biomass as well [24, 25]. It consists of high proportions of organic matter, but it also contains numerous non-organic residues such as metals or glass, so treatment would have to be adjusted. In addition, it cannot be regarded as a fully renewable energy source. For the purposes of this project, MSW will therefore be excluded from the definition of biomass.

In general, biomass is a heterogeneous mixture of a large number of different organic carbohydrate molecules. It mainly consists of carbon (C), hydrogen (H) and oxygen (O), with minor amounts of nitrogen (N) and sulphur (S). Although the molecular structures differ significantly from one biomass source to another, a number of main properties can be defined for all different sources. For the purpose of power generation, these main properties are moisture content, calorific value, composition and proportions of inert material [18]. Of these, one main property decides about the main classification of biomass as a feedstock and about the technology to be applied when using it as a feedstock for energetic purposes: this property is the water (or moisture) content [18].

The moisture content of a biomass source is defined as the weight percentage of water contained in the biomass and can vary within nearly the whole theoretical range of 0-100wt%, from nearly 0% for oven-dried wood chips to well above 95% for highly diluted manure. In general, straw, grasses, wood and crops have a relatively low moisture content, whilst manures, vegetable wastes and diluted industrial by-products have a high moisture content.

The biomass moisture content is a critical property when it is to be used for energetic purposes, as it strongly influences the calorific value (or heating value) of the biomass. This value is defined as the amount of heat energy released by burning a unit of mass or volume of biomass. Whilst the higher heating value (HHV) includes the latent heat of the water vapour, i.e. the energy of condensing the water vapour, the lower heating value (LHV) subtracts the heat of vaporisation from the higher heating value. As the latent heat of water vapour cannot be used when applying biomass for power generation, the lower heating value is the more practical value for biomass application – and it is the value that will be referred to as calorific or heating value throughout this thesis.

The LHV however linearly depends on the moisture content: with rising water content more energy is necessary for water vaporisation and the 'useable' energy decreases. To distinguish between biomass conversion and generation technologies, two main biomass categories were defined in literature on the basis of its moisture content: Dry biomass with a moisture content of below 50%, and wet biomass with a moisture content of above 50% [18]. The following two sections will describe each category in more detail.

4.1.1 Dry Biomass

The maximum level of moisture content for dry biomass is around 50%; in general, wood and waste wood, straws and grasses as well as other plants fall within this category. However, the moisture content depends not only on the material properties but also on the harvesting and storage methods, so this level is not absolute. Freshly cut wood for example contains between 30-60% water, depending on the season and the harvesting methods [14, 26, 27]. This initial moisture content also decreases during storage of the wood logs, which is shown in the example drying curve in Figure 4-2 [14] depicting the moisture content as a function of storage time.

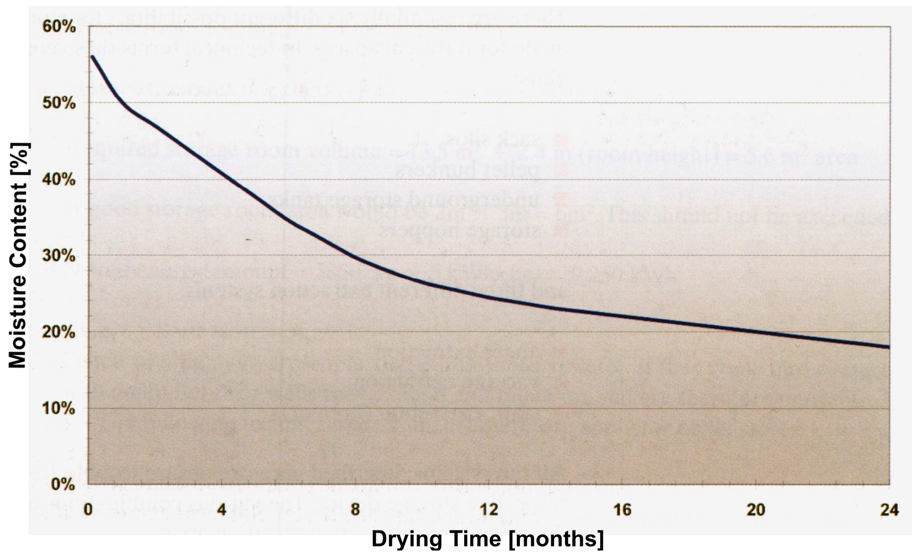

Figure 4-2: Drying Curve of Wood Logs (Source: adapted from [14]).

The calorific value of dry biomass however, despite their very different molecular structure and physical properties, varies only slightly for nearly all biomass sources; it is around 20MJ/kg for a moisture content of 0%, compared to around 33MJ/kg for coal [18, 28, 29].

Since the moisture content of biomass is relatively low, it can be burnt directly to produce heat by releasing its chemical energy; alternatively, it can be converted into intermediate fuel. Such intermediate fuel has a higher energy density and can be stored more easily than raw biomass feedstock, so the conversion to fuel can be more economical than direct combustion.

When describing and classifying the properties of a dry biomass source to be used for energy purposes such as power generation, it is common practice to use the property frameset of coal, due to the similarities of the two substances. In both cases, the actual molecular composition of the substance for example is irrelevant, and instead a number of properties that affect its behaviour in industrial processes are defined to classify and compare one substance to another.

Therefore, dry biomass is defined by means of its proximate and ultimate analysis. Whilst its proximate analysis defines the ratio of several products after heating the biomass, its ultimate analysis determines its atomic composition [28].

The *proximate analysis* of a substance reveals the amounts of moisture, ash, volatile matter and fixed carbon, which are received when heating the substance [28]. All are given as a percentage of the initial, so the sum of these four categories is 100%. Its moisture content, as discussed above, is a crucial property when it comes to utilising the biomass as an energy carrier. The ash content is the percentage of inert residue remaining after complete combustion, and depends on the mineral matter of the biomass. Ashes are numerous mineral oxides which are formed during combustion, and they are related to potential problems of fouling and slagging within the biomass utilisation processes. In addition, high ash contents are related to lower obtainable energy amounts, due to the ash being inert. The volatile matter (VM) category defines the percentage of substance that has changed from solid to gaseous or vapour state during the heating, which means that it is the difference between the solid mass before and after the heating process, but excluding the moisture. The volatile matter of biomass mainly consists of the combustible gases formed during pyrolisation processes, so this value provides information on the amount of light substances that can be achieved from the biomass. Finally, the fixed carbon (FC) category contains the percentage of mass which, after heating, remains as the solid residue, excluding the ash. This can be defined as the pyrolisation char, which contains considerable energy stored in chemical bonds of long carbohydrate chains. During conversion processes, this char can be cracked into shorter molecules and liquid or gaseous substances can be obtained.

The *ultimate analysis* of a substance provides its atomic composition in the form of percentages of carbon, hydrogen, oxygen, nitrogen, sulphur and ash [28]. Irrespective of the actual organic structure of the substance's molecules and the chemical bonds that the single atoms have entered into, this analysis provides the relative amount of its atoms, which provides important information on the achievable energy when using the biomass for power generation.

Similar to the calorific value of different biomass sources, their proximate and ultimate analyses also vary very little and can therefore be assumed to be constant. Numerous proximate and ultimate analyses of different biomass sources have been performed and published, and based on these values [18, 23, 30-33], typical proximate and ultimate analyses for wood chips are shown in Table 4-I and Table 4-II, respectively.

Table 4-I: Wood Chips – Proximate Analysis [wt%].

Moisture	Ash	Volatile Matter	Fixed Carbon
20.0	1.22	65.02	13.76

Table 4-II: Wood Chips – Ultimate Analysis [wt%].

C	H	O	N	S	Ash
49.48	5.38	43.26	0.35	0.01	1.52

4.1.2 Wet Biomass

Wet biomass classifies all biomass sources with a water or moisture content of significantly above 50%. In the context of this project these are mainly livestock manure and other diluted substances such as vegetable or food wastes, whilst algae and industrial process wastes such as bagasse and pulp liquor also count towards this category. However, the availability of industrial process wastes is somewhat unlikely for the scope of this project, hence the focus will be laid on livestock manure and vegetable or food wastes.

As moisture contents for some wet biomass sources can be up to more than 90%, it has become convention to define a property called dry matter content, which replaces the moisture content. The dry matter content (DM content), often also referred to as total solids content (TS content) is the amount of all solid matter, given in vol-% of the biomass [14, 34]. Food processing residues and vegetable wastes, as well as chicken manure, have a DM content of around 40-50% and are therefore on the upper limit of wet feedstock. In comparison, cattle, sheep and pig manure have significantly lower DM contents of around 6%-14% [35, 36]. The DM content of the feedstock strongly influences the reactor size and hence its setup and operational cost, since low DM contents require larger reactors to handle the same DM volume [34].

Whilst the DM content is the property to describe the operational impact of a wet biomass feedstock, its organic matter is the property that influences its applicability with regards to energy extraction. The organic matter (OM) content, also referred to as volatile solids (VS) content, is the fraction of feedstock which contains all organic contents, and which during the conversion processes can be used to release energy [14, 34]. It depends on the organic composition of the feedstock and can be compared to the volatile matter content of dry feedstock.

The calorific value of biomass feedstock, as mentioned above, linearly decreases with increasing water content, which means that the high water content of wet biomass sources results in special treatment needs. Thermochemical conversion technologies in general are unsuitable for wet biomass feedstock due to the amount of energy that would be necessary to vaporise the water from the feedstock. Instead, a number of treatment technologies have evolved that can be applied to wet feedstock. Those processes are called biochemical conversion technologies and mainly use selective micro-organisms which are not restricted by high water contents in the feedstock.

4.2 Conversion Technologies

The first step in transforming raw biomass into a useful energy carrier is converting it into a state more suitable for energy extraction. Due to the aforementioned linearity between water content and energy content of biomass, conversion technologies have evolved in two main categories: technologies that transform dry feedstock on the basis of thermochemical processes; and technologies that transform wet feedstock on the basis of biochemical processes. Thermochemical processes change the molecular structure of the feedstock by applying energy through heat and/or pressure. They require relatively dry feedstock in order to be efficient, otherwise significant amounts of energy are wasted on applying heat and pressure to the inert water contained in the feedstock. In contrary, biochemical processes use micro-organisms that selectively convert the feedstock molecules during their growth processes and therefore are relatively independent of the water content of the raw biomass.

A detailed literature analysis of conversion technologies was undertaken and will be described in the following sections. It will be evaluated which conversion technologies exist, in which state of development they are, what feedstock they are suitable for and what their advantages and disadvantages are. On this basis, those technologies that can be applied to the design of this project will then be evaluated through comparison and ranking.

4.2.1 Thermochemical Conversion Technologies

Thermochemical conversion technologies convert or release the energy contained in biomass feedstock by means of applying heat and/or pressure. During thermochemical conversion processes, the chemical bonds of the large biomass molecules are cleaved and large macromolecules are converted into smaller, shorter hydrocarbon molecules. Thermochemical conversion technologies include gasification, pyrolysis and liquefaction. Gasification is the high-temperature partial oxidation of feedstock, whilst pyrolysis applies medium temperatures in the absence of air to cleave the biomass molecules. Finally, liquefaction is a low-temperature and high-pressure process to convert biomass into liquid fuels.

4.2.1.1 Gasification

Gasification is the partial oxidation of solid biomass particles into a producer gas mainly consisting of carbon monoxide (CO), hydrogen (H_2), carbon dioxide (CO_2) nitrogen (N_2) and methane (CH_4) [27]. Oxygen is supplied at high temperatures of around 700-1000°C and oxidises the biomass carbohydrates [37-41]. To prevent complete combustion of the feedstock, the amount of oxygen is restricted, so gasification can be regarded as incomplete combustion. This results in products which still contain energy and whose energy can be extracted in later processes – which means that they have become an energy carrier, or fuel. The main energy carriers of gasification, CO and H_2, are in gaseous state, hence its name.

The oxygen can be supplied as air, steam or pure oxygen, and different producer gas calorific values are the result. Using air as the gasification agent results in producer gas with a calorific value of around 5MJ/Nm^3, whereas the use of pure oxygen or steam results in producer gas with a calorific value of 10-12MJ/Nm^3 and 15-20MJ/Nm^3, respectively [27, 42]. This difference is mainly due to the inert nitrogen when using air instead of steam or pure oxygen. In comparison, natural gas with a methane content of normally more than 95% has a calorific value of around 44MJ/Nm^3 [43].

During the gasification process, a number of complicated reactions occur; however, three main steps are differentiated: first the particle drying process, where all water is evaporated; followed by the pyrolysis process, where the particle is broken up into volatiles and a char residue; finally the oxidation process, where the volatiles, which are a mixture of different organic and inorganic compounds, are oxidised by the gasification agent and part of the char is reduced by carbon dioxide and water into hydrogen and carbon monoxide [29]. Two main by-products are created during the gasification process and can constitute up to 10% of the intake mass: particulates, i.e. unconverted or partially converted biomass char and inert substances such as ash or other impurities of the biomass feedstock; and tars, i.e. long-chain organic compounds which were not or only partly oxidised [42].

As the oxygen needs to cleave the biomass macromolecules, a high surface area is favourable and therefore biomass needs to be provided in the form of chips or particles. Particle size requirements vary from one reactor design to another, but in general are between a few mm to 5cm; they can contain maximum moisture contents of up to 30-50%, however should in general be below 20% [29]. It should at this point be noted that a certain amount of water in the feedstock is favourable due to a water hydrogen shift reaction which results in a higher calorific value, a fact that is also employed in steam gasification.

Gasification technology is not a new technology, and therefore numerous gasifier designs exist and have been tested extensively [29, 42, 44]. Due to the chemical reactions that occur in the reactor and since considerable levels of heat need to be provided, most systems and especially all large scale gasifiers are designed and set up for continuous and steady operation. Although the feedstock input flow can be varied, a rather steady throughput and thus producer gas output should be aimed for. Start-up times for smaller gasifiers of around 10-20min were reported [45, 46].

Most gasifiers are operated under atmospheric pressure levels in order to keep the reactor design simple. However, due to producing a rather low-calorific gas, it has been investigated whether using pressurised equipment provides benefits by means of smaller equipment for the same throughput rates. In addition, using the producer gas in generation engines can require a certain minimum energy density, which may make gas compression mandatory. In this case, pressurised gasification may be advantageous as only the gasification agent needs to be compressed, whilst with atmospheric gasification a far higher volume of producer gas needs to be compressed, which can amount to a significant energy input [42, 47, 48]. Pressure ranges of 3-10bar have been investigated, however the cost impacts of employing pressurised equipment outweigh its benefits, especially for smaller scales [49-51].

Although all gasification units operate on the same fundamental processes, a broad range of reactor designs has evolved in literature. In general, three main categories can be differentiated, depending on the velocity of the gasification agent in relation to the biomass particles: fixed-bed reactors, fluidised bed reactors and entrained flow reactors (e.g. [27, 29, 42, 52]).

In *Fixed-Bed Reactors*, the gasification agent velocity is relatively low, and it steadily flows through the biomass particles. This reactor design is comparably simple and cost-competitive. Besides, variable particle sizes and feedstock qualities can be handled, so this design is the preferred option for small scale applications. Co-current (downdraft) reactors employ the same flow direction for biomass particles and the gasification agent. In contrast to that, counter-current (updraft) reactors are operated by the counter-current flow principle, i.e. biomass particles flowing from top to bottom whereas the gasification agent flows from bottom to top. Figure 4-3 shows a schematic of the two different designs [44], and their main advantages and disadvantages are covered in Table 4-III.

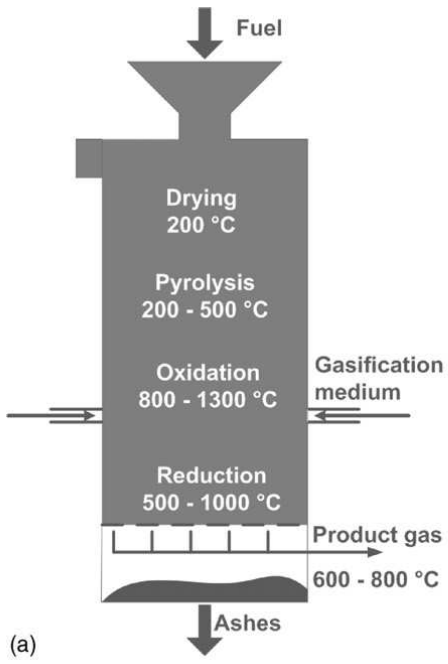

Figure 4-3: Schematic of a) Co-Current and b) Counter-Current Fixed Bed Gasifiers (Source: [44]).

Table 4-III: Advantages and Disadvantages of Co-Current and Counter-Current Gasification.

Co-Current Fixed Bed	Counter-Current Fixed Bed
• comparably clean producer gas due to exiting at the bottom directly after conversion of biomass, therefore better suited for small scales • lower mixing intensity and problem of clogging of biomass particles due to co-current flow, therefore requires steady feeding of the particles • high temperature of exiting gas (700°C), possibility to employ heat in other processes	• high amounts of tar in exiting gas due to contact with entering biomass, therefore need for gas cleaning equipment • intensive mixing of particles and agent due to counter-current flow, resulting in higher conversion rate • good heat transmission from the hot producer gas to the entering biomass particles, thus relatively cold exiting gas (100-200°C)

Fluidised-Bed Reactors employ a higher gasification agent velocity and a reactor bed consisting of biomass particles and inert material such as sand which facilitates the heat transmission. Advantages of fluidised-bed reactors are higher conversion rates due to the better mixing of agent and biomass, lower tar contents and better heat transmission from the bed material to the biomass feedstock. However, this design necessitates cyclones to separate bed material and unconverted particles from the exiting producer gas system and reactor loops to re-cycle the bed material into the reactor. Fluidised-bed reactors are therefore limited to larger scales of >1MW [29].

Entrained Flow Reactors employ an even higher gasification agent velocity and result in an evenly distributed stream of particles and gasification agent throughout the reactor. They provide the highest mixing rates and therefore result in very high conversion rates and clean gas. However, since they employ a high velocity and only a very short retention time, a very small particle size of <20mm is necessary to facilitate conversion, which requires sophisticated particle pre-treatment. Even though their feasibility is already limited to scales above 2.5MW, the cost impact of this pre-treatment and operational challenges have so far hindered the wide-spread application of these systems [29, 42, 53].

The schematic in Figure 4-4 [54] shows two types of fluidised-bed gasifiers ('bubbling' and 'circulating') and an entrained flow gasifier.

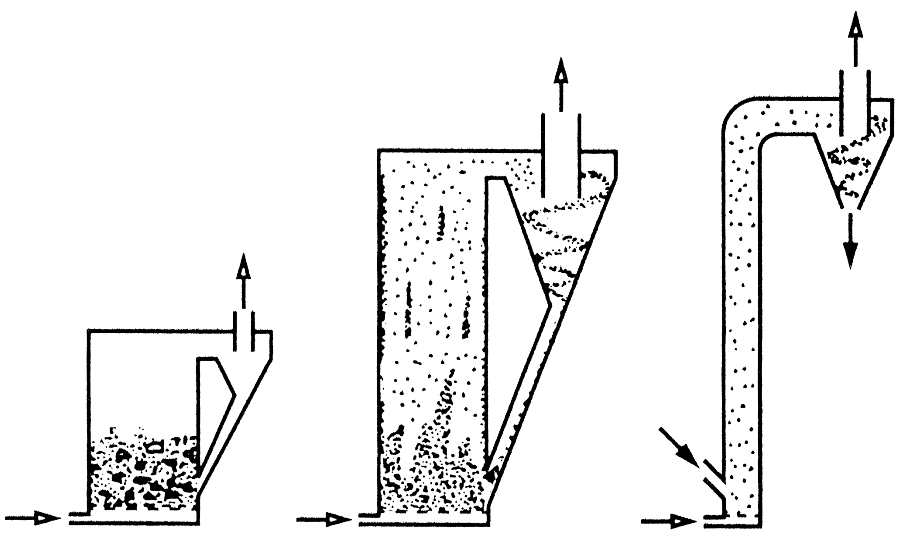

Figure 4-4: Schematic of Bubbling and Circulating Fluidised Bed and Entrained Flow Gasifiers (Source: [54]).

Irrespective of the type, design and size of the actual gasification reactor, the producer gas will always contain particulate and tar as by-products due to the very nature of gasification, as discussed above. Whilst the more complex fluidised-bed and entrained flow gasifiers in general will have a very low tar and particulate content, the simpler fixed bed gasifiers can contain significant amounts of particulate and tar. As a result, treatment of the producer gas to clean it of these by-products may be necessary depending on particulate and tar limits of the technology that will be operated with the producer gas. Whilst particulate filtering can be achieved relatively easily even for small-scale gasifiers, tar contents have been a major obstacle that in history hampered the application of especially small fixed bed gasification systems [42, 44, 55-58].

Due to the intended plant size for this project, only fixed bed gasifiers are a viable option, therefore their typical particulate and tar contents were analysed and are shown in Table 4-IV for both downdraft and updraft designs [55]. Limits for employing producer gas in the two main fuel-based generation technologies *Microturbines* and *Internal Combustion Engines* [53] (see section 4.3.2) are also shown in the table.

Table 4-IV: Particulate and Tar Contents of Fixed-Bed Gasification and Limits of Producer Gas Use in Generation Technology.

	Particulate Content [mg/Nm^3]	Tar Content [mg/Nm^3]
Producer gas from:		
Co-current Gasifiers	50-500	50-1,000
Counter-current Gasifiers	100-3,000	10,000-150,000
Limit for producer gas use in:		
Microturbines	30	50-100
Internal Combustion Engines	50	50-100

It can be seen that tar levels especially for counter-current gasifiers are significantly above the limit for application in generation equipment, which is due to the aforementioned contact between exiting producer gas and entering biomass for heat exchange reasons, see Table 4-III. This however means that producer gas from counter-current fixed bed gasifiers will not be viable for fuel-based generation purposes [42, 44].

In contrast to that, co-current fixed bed gasifiers can already provide tar and particulate levels that are within the limits for generation, which is largely due to the increased research and development activity towards tackling tars in gasification in the last years. Designs have improved significantly over the last decade and some co-current gasifier designs can now produce gas which can be used in generation equipment without the need for cleaning equipment [44, 59]. In addition to these ongoing advances of gas cleaning and tar reduction, some newer gasifier designs have also achieved the production of virtually tar-free gas [37, 60-62], and further improvements in this area are to be expected in the near future. It can therefore be concluded that suitable co-current fixed bed gasification reactors without the need of extensive gas cleaning exist in a fitting scale for this project.

4.2.1.2 Pyrolysis

Pyrolysis is the conversion of solid or liquid biomass into a mixture of liquid, gaseous and solid intermediate fuels by means of heat energy in the absence of air [41]. Biomass particles are heated, and their water content is vaporised. Afterwards, the particle is broken up into char and a volatile compound, of which the latter is then partly cracked into gaseous products. The energy applied to the biomass feedstock cleaves the biomass macromolecules into volatiles, and since no air is provided, no oxidation processes occur, which means that the products of pyrolysis are un-oxidised volatiles and gases. The pyrolysis process can thus be described as incomplete gasification, since the final part-oxidation step of gasification is omitted [42].

The main product of pyrolysis is the liquid phase, a mixture of a complex range of organic and inorganic compounds diluted in water, which is called bio-oil. However, one of the main advantages of pyrolysis is the possibility to adjust the ratio of the three products (char, bio-oil, gases) by varying the process parameters. The gas phase yield can be increased by high temperatures and long residence times to intensify cracking processes. Moderate temperatures and short residence times result in a maximum amount of bio-oil by preventing the oil cracking. Finally, low temperatures and long residence times maximise the char residues [42, 63].

Based on these adjustment options, three different pyrolysis processes are classified in literature: *Conventional Pyrolysis* (or *Carbonisation*) with low heating rates and temperatures and high particle retention times of up to several minutes; *Rapid* or *Fast Pyrolysis* with medium to high temperatures and heating rates and shorter retention times of several seconds; and *Flash Pyrolysis* with very high temperatures and heating rates and very short retention times. However, very high heating rates correspond with the need for smaller and very uniform feedstock particles to facilitate rapid heating, an effect resulting in very high feedstock prerequisites and thus pre-processing costs [42, 63-65].

Temperature levels for pyrolysis are significantly lower than gasification temperatures and vary around 300-500°C, depending on which pyrolysis process is employed [42, 63, 66-68]. The heat energy necessary to pyrolyse the biomass needs to be supplied without introducing oxygen into the reactor, so most pyrolysis processes employ external combustion of the char residue and heat exchangers to heat the reactor [69-72]. Some designs also include a separate combustion area within the pyrolyser where some combustion air is introduced for combusting the char [56, 73].

Numerous pyrolysis reactor designs have been introduced for both larger and smaller scales, however *Rapid, Fast* and *Flash Pyrolysis* are more viable for larger scales due to the high heating rates and the more intensive particle pre-treatment to achieve small particle sizes in the region of several millimetres. However, only very few pyrolysis reactor designs have reached commercial status [66, 67, 74], since oil and gas yields are comparably low.

Other obstacles of pyrolysis which still need to be overcome are the water dilution of the bio-oil and its corrosivity. Since bio-oil is created under absence of oxygen, its main components tend to oxidise when getting in contact with air. This however means that the storage of bio-oil and its application in generation technology is limited, which has hindered the general development of pyrolysis processes [75].

4.2.1.3 Liquefaction

Liquefaction is the last conversion technology within the thermochemical group. Whilst gasification and pyrolysis mainly use reactions driven by heat energy to cleave the biomass macromolecules, liquefaction applies high levels of pressure and only moderate temperatures. During liquefaction, biomass particles are brought in contact with a suitable catalyst that, under high pressure, decomposes the long hydrocarbon chains into shorter reactive fragments, which then re-polymerise to form an oily substance [76].

Common process parameters are temperatures of around 200-400°C and pressure ranges of 50-200bar [41, 76-78]. The main product has a composition similar to pyrolysis bio-oil, however it has a higher calorific value and a lower oxygen content than bio-oil, which make it the higher-quality substance of the two [76]. Another advantage of liquefaction when compared to pyrolysis is that drying of the feedstock is unnecessary [76]. The water contained in the biomass does not impact the energy input of the process, as liquid water has no influence on the application of pressure, and as only moderate temperatures are used in the liquefaction process.

A considerable number of biomass feedstocks can be liquefied, such as wood, bark, bagasse, and husks and shells of coconut, oil-palm and rice. However, the oil yields that were achieved are around 20-50% of the feedstock mass, which is considerably below the respective pyrolysis values [79, 80]. This combined with the very high pressures of the liquefaction reactor and encompassing equipment and the need to employ catalysts have basically made this process economically infeasible, and although liquefaction was performed as early as in the 1970s, there are currently only very limited investigations to make liquefaction commercially available [76, 80].

Even less interest can be expected for small scale applications due to the further cost impact of pressurised equipment at this scale, so of all thermochemical conversion technologies, liquefaction is in the earliest stage of development for small scale applications and seems not feasible in the near future [41, 77].

4.2.2 Biochemical Conversion Technologies

Highly diluted biomass such as manure and food or vegetable wastes cannot be treated economically in thermochemical conversion reactors due to the energy input necessary to heat the feedstock and to vaporise the water. Thus, for feedstock with significantly more than 50% moisture, biochemical treatment at comparatively low temperatures becomes a more economic solution. Two main processes can be differentiated: *Anaerobic Digestion* (AD), where biomass is converted by bacteria, and *Fermentation*, where yeasts are used to convert biomass. Whereas AD is the standard process for treating very high dilution levels, fermentation can also be applied to lower water contents.

Both processes are well-known technologies with a long history of application. Fermentation to convert sugars into drinkable ethanol has been applied for centuries; similarly, AD has been used for decades to treat manure for hygienic and odour control reasons, and to create fertiliser. Only relatively recently though have these processes become relevant from an energy extraction point of view [81-83].

4.2.2.1 Anaerobic Digestion

Anaerobic digestion is the bacteria-driven conversion of biomass in the absence of oxygen. The micro-organisms depolymerise the biomass macromolecules and deplete its oxygen content as they gain energy from the biomass [84]. During this bacterial growth process, they produce gases as an ‘unwanted’ side-product. This gas mixture, albeit unuseable by the micro-organisms, still contains energy stored in the chemical bonds of the gases and can be used as fuel. It is called biogas and is a mixture of around 45-75% of CH_4 and the remainder of CO_2 and some minor components.

In general, around 30-60% of the digestible material, which mainly consists of the volatile organic solids, is converted into biogas. The processes of anaerobic digestion are very complex and a large number of chemical reactions occur during the bacterial growth processes, however Figure 4-5 shows the main consecutive steps of AD [14].

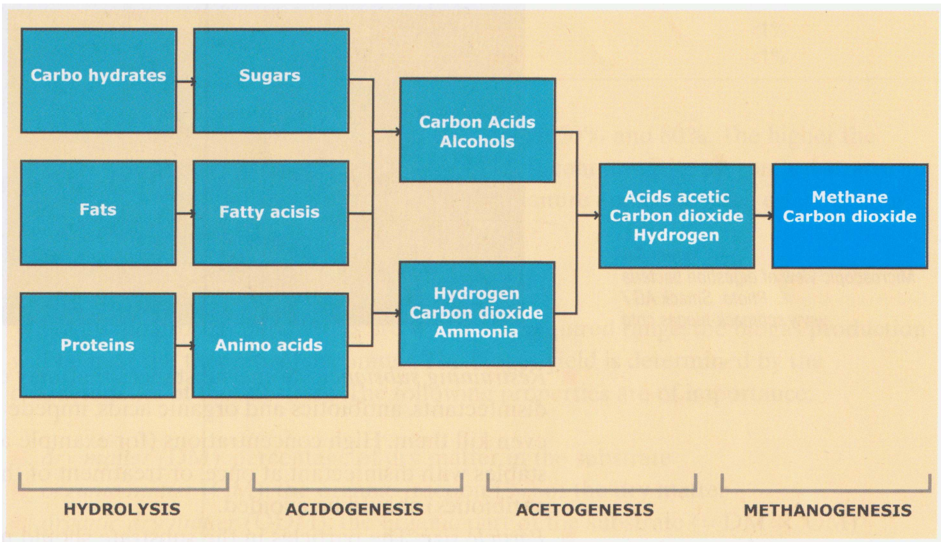

Figure 4-5: Anaerobic Digestion Process (Source: [14]).

Anaerobic digestion processes can be initiated by filling biomass into an air-tight reactor which already contains active bacteria strains, and by keeping the reactor at a certain temperature level. The bacteria strains require a constant temperature level for their growth processes, and three different bacteria strains can be categorised: psychrophilic (~15°C), mesophilic (~35°C) and thermophilic (~55°C) bacteria [34, 85, 86]. All three AD temperature levels are comparably low and therefore the heat energy demand is relatively easy to provide, for example by using exhaust heat from generation units or other plant processes.

The bacterial growth processes do not occur instantaneously, but instead they happen comparably slowly and steadily; therefore, biomass needs to be kept in the reactor for between 15-25 days. However, to continuously provide new digestible material, part of the digester volume is regularly discharged and replaced by new feedstock, and the gas production is further enhanced by regular mixing or stirring of the reactor [84].

With regards to plant size, AD reactors can cover a wide range of scales: on the basis of their volume, *Small Scale*, *Farm Scale* and *Industrial Scale* digesters can be classified, with <100m^3, 100-800m^3, and >800m^3, respectively [14]. Figure 4-6 [87] and Figure 4-7 [14] show examples of each scale.

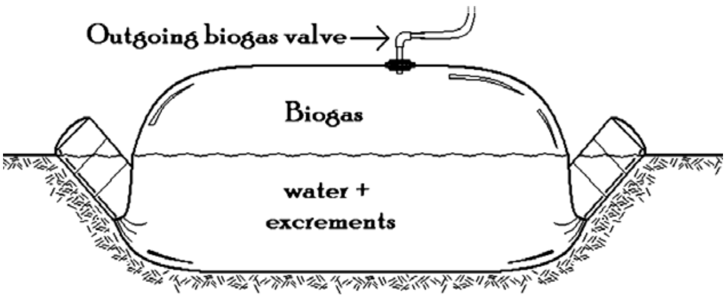

Figure 4-6: Small Scale Anaerobic Digester (Source: [87]).

Figure 4-7: Farm Scale and Industrial Scale Anaerobic Digesters (Source: [14]).

Feedstock acceptability is high: all livestock slurry as well as organic farm wastes and even cellulose-containing material can be treated in AD plants to produce biogas. The by-products of AD, which are discharged from the reactor, are settled fibre useable for soil conditioning and liquid fertiliser which can be used on the farm without additional treatment [34, 35, 84, 88]. As mentioned before, AD is not a new technology, however its historic use was limited to produce suitable fertiliser from manure, whilst the biogas itself has just relatively recently become an interesting energy source [81-83].

The feedstock utilisation rate, and thus the biogas production rate, highly depends on the temperature of the reactor and on the bacterial strain employed. Figure 4-8 shows the relative methane yields of the three bacteria strains as a function of the retention time and thus depicts the relative activity of methane generation [14]. Thermophilic bacteria result in the most active growth processes, hence for common retention times of 15-25 days they provide the highest biogas yields. However, their drawback is that they are very susceptible for external influences such as temperature changes or fluctuating feedstock composition, therefore their process stability is relatively poor. In comparison, psychrophilic bacteria have very slow growth processes and thus result in either very long retention times, or low biogas yields, which both make them less promising from an energy conversion point of view, although psychrophilic reactors are very stable and robust from an operational point of view [89]. Mesophilic bacteria are in-between these two extremes, and their still relatively high conversion rates combined with their robustness make them the standard choice of most commercial farm digesters [34, 90, 91].

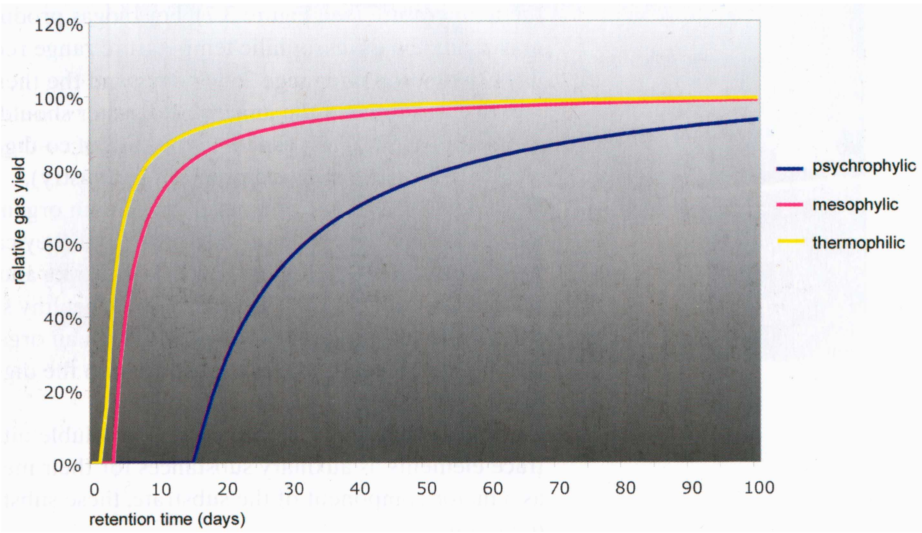

Figure 4-8: Methane Yields of Psychrophilic, Mesophilic and Thermophilic Bacteria (Source: [14]).

4.2.2.2 Fermentation

Fermentation is a conversion process to turn biomass into ethanol (EtOH). The final product ethanol can be gained from sugars through the application of yeasts, so depending on the feedstock composition, fermentation consists of one or two process steps. For those biomass feedstocks that predominantly consist of, or are rich in, sugars, the fermentation process only consists of inoculation with yeasts, and after 1-3 days at 20-30°C, the raw ethanol yield is obtained. This process can be applied for feedstock such as sugarcane, sugar beets or fruit wastes [41, 92].

Feedstocks which are rich in starch, such as corn or vegetable wastes, first need to be converted into sugars before ethanol can be obtained. This process is called hydrolisation and requires the adding of enzymes and cooking the feedstock at temperatures of around 140-180°C. Although conversion rates are very high, the energy requirements are substantial, and adding the enzymes also increases process cost, so starch fermentation is currently limited to industrial scale plants [92]. Similar issues occur when feedstocks contain high amounts of cellulose, such as for wood, agricultural residues or pulp liquor. Again, cellulose first needs to be converted into sugars before fermentation into ethanol can be achieved, but enzymatic cellulose hydrolisation is a less mature process than starch hydrolisation. This is due to the composition of cellulose-rich biomass, whose complex carbohydrate polymers need to be liberated and depolymerised to form sugars. Therefore, those feedstocks seem less favourable and feasible both economically and technically when compared to sugar-rich feedstocks [31, 41, 92].

In either case, the fermentation process produces a diluted raw alcohol which contains between 5-15% EtOH, with the rest being water and unconverted feedstock [31, 92]. This raw alcohol then needs to be distilled to higher concentrations before being used as fuel, a process which is highly energy-intensive [41, 76].

Ethanol as the final fermentation product allows easy handling and storage compared to gases, but due to the intensive feedstock pre-treatment, the necessary temperatures, enzymes and yeasts, and the diluted intermediate product with the need of further distillation steps, the fermentation process is significantly more complex than anaerobic digestion. Despite the given advantages of storage and transport, it is these difficulties and energy requirements that have led to fermentation being treated as less suitable for energy purposes than AD, especially for smaller scales.

4.3 Generation Technologies

Generation technologies are employed to convert the energy stored in the fuel into electrical power and/or heat. They release the chemical energy stored in the fuel molecules by combustion, and thus convert it into thermal energy and work. Depending on the generation technology, either or both of these energy streams are then converted into kinetic energy, which is used to drive a generator to generate power. Part or all of the thermal energy released during the process can be fed back into the plant system should heat energy be needed within the upstream processes; alternatively, heat can also be supplied to the customer as a product, in which case the plant system is called *Combined Heat & Power* (CHP).

Domestic customers may require heat for space heating, thus residential CHP plants provide heat through hot water of around 70-90°C. Alternatively, and more suitable for industrial customers, heat can also be supplied in the form of steam or hot exhaust gas. Finally, should there be insufficient demand for heat from the customer, heat streams can be utilised for internal processes such as feedstock drying or preheating. As long as sufficient internal heat demands exist, this last option increases the process efficiency. Less energy needs to be provided by the fuel, which increases the fuel production rate and decreases consumption.

Two main generation technology categories were established in industry and literature: *Heat-Driven* technology, covering all engines that directly apply combustion heat and that can thus be operated on raw feedstock; and *Fuel-Driven* technology, covering engines that utilise the expansion work of combustion flue gases and therefore require solid, liquid or gaseous fuel of a certain quality to operate. Stirling Engines and Externally Fired Gas Turbines belong to the heat-driven category and can be operated on raw unconverted biomass feedstock, whereas Microturbines and Internal Combustion Engines/Gas Engines belong to the fuel-driven category.

4.3.1 Heat-Driven Generation

Heat-driven generators produce electricity by directly applying the thermal energy of combusting raw biomass feedstock. They therefore do not need any conversion technologies, but they can also be operated on preconditioned fuel of higher quality. The feedstock is combusted in a furnace, grate or boiler, and hot exhaust gases with temperatures of around 800-1000°C are generated [41]. The thermal energy of these hot gas streams is then used to run the engine, and ultimately to generate power.

Combustion technology such as furnaces and grates are very simple to set up, however they suffer from relatively low efficiencies of around 10-25% [93, 94]. Due to the inherent immediate release of all chemically stored energy during fuel combustion, adjusting the output level, and hence flexible operation, is very difficult. Adjustments can only be made by changing the feedstock input, however response times are long as the combustion process itself proceeds relatively slowly.

Combustion technologies have a long history of providing heat, from cooking and space heating for domestic customers to high temperature combustion ovens and steam raising units for industrial customers. They are also the main technology for large scale power generation, as coal, gas and oil fired power plants consist of large scale steam turbines whose steam is provided by combustion processes. However, their application for smaller scale and flexible power generation is somewhat limited [41]. Two main technologies have evolved in this context: *Stirling Engines* and *Externally Fired Gas Turbines*.

4.3.1.1 Stirling Engines

Stirling engines are designed to generate electricity by cycling a sealed working gas through a continuous heating and cooling process that consists of four steps:

I. The cold gas is compressed through work at a piston.

II. The compressed gas is then heated in a heat exchanger.

III. The hot compressed gas is expanded and provides work at a piston.

IV. The expanded gas is then cooled in a heat exchanger.

The net work of the cycle is the piston work of step III minus the work needed to compress the gas in step I. This amount of work can then be used to generate electricity. By employing two geographically divided rooms to heat and cool the gas and by combining the pistons to a crankshaft, a continuous process can be designed, a schematic of which is shown in Figure 4-9 [95].

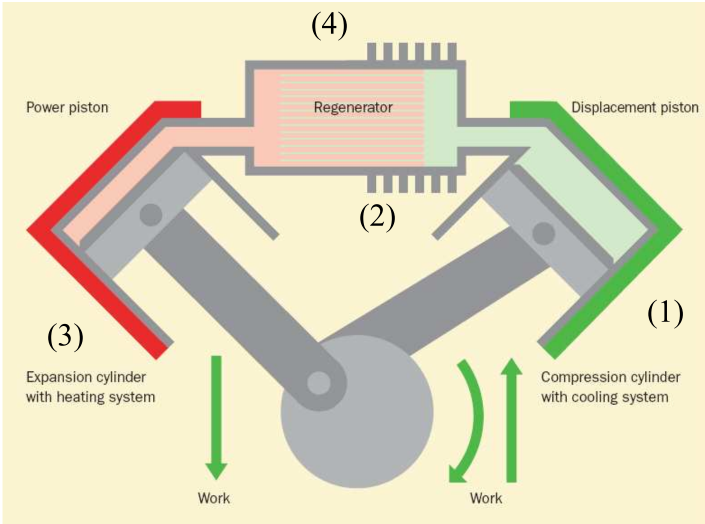

Figure 4-9: Schematic of an Alpha-Type Stirling Engine (Source: adapted from [95]).

The Stirling engine uses the thermal energy of the combustion flue gas in the heat exchanger to heat the cold uncompressed working gas in step II to temperatures of 700-800°C [57, 96, 97]. However, this means that a significant amount of heat from the combustion gases will not be used by the Stirling engine at all. In addition, not all energy transferred to the working gas will be converted into piston work, as in step IV thermal energy will be extracted from the working gas during cooling. Therefore, the electrical efficiency of Stirling engines is in the range of 20-25% and hence rather low [57, 97-100]. Coupling the Stirling engine to a CHP unit to use the remaining thermal heat from the combustion gases and from the heat exchanger in step IV and to supply hot water for space heating is thus recommendable to increase the overall efficiency.

The working gas used in Stirling engines normally is either helium or hydrogen [57, 101], however air can be used as well as long as it can be provided clean and oil-free; its high availability and the fact that the performance is not impacted by the kind of working gas make it favourable especially for remote applications [97].

The output power level of Stirling engines generally depends on the working gas pressure and on the temperature difference between the hot and cold zone [100, 101], and for the small to micro scale power level, numerous Stirling engines have been designed, tested and applied [95, 97, 101-105]. Figure 4-10 shows an example of a 35kW$_e$ engine from a Danish manufacturer [96].

Figure 4-10: 35kW$_e$ Stirling Engine from Stirling Denmark (Source: [96]).

The main advantage of Stirling engines is their fuel flexibility. Nearly all biomass is suitable for combustion, and even ‘dirty’ feedstock can be used because the exhaust gases do not have direct contact with moving parts of the engine. This separation between combustion flue gases and working gas results in exceptionally long-lasting operation cycles, and continuous running intervals of 8,000-10,000hrs between maintenance stops are common [95, 104], which makes these engines well-suited for remote locations and automated operation.

Due to the continuous combustion process and the time necessary to transfer the combustion heat to the working gas, Stirling engines in general are designed for steady state base-load performance. The output power is normally adjusted through the amount of thermal energy transferred in the heat exchanger, which is called heat-led operation and results in very long response times. This means that a Stirling engine should mainly supply a defined heat demand, with electricity being generated in addition to serving this heat load.

In contrast to heat-led operation, electricity-led operation is defined as adjusting the power output of the engine to meet a variable electrical demand. In this operation mode, the engine needs to follow the electrical load, and heat is provided as an additional output. This mode of operation however requires part-load operation, i.e. less than nominal power output, and although some trials were reported as promising [106], Stirling engine part-load operation seems very difficult and results in even lower efficiencies than under nominal load [96]. Additionally, Stirling engines in general are still mentioned as being comparably less mature than other generation technologies [75].

4.3.1.2 Externally Fired Gas Turbines

Externally Fired Gas Turbines (EFGT) are an adaptation of microturbine technology to overcome the quality requirements of microturbine fuel, as will be described in section 4.3.2.1 below. Microturbines are commonly defined as gas turbines for a power range of less than $500kW_e$; they generally have a combustion chamber to burn their fuel, and a turbine to expand the combustion flue gases. However, EFGT designs replace the combustion chamber with a heat exchanger. This means that the turbine uses a working gas similar to the Stirling engines, and combustion of the biomass takes place in external combustion furnaces or grates. High-temperature heat exchangers are then used to transfer the heat from the combustion flue gas to the turbine working gas.

A schematic of the EFGT process is shown in Figure 4-11 [107], where 'Rec I' and 'Rec II' are the two heat exchangers or recuperators, and 'cc' is the biomass feedstock furnace or grate. It can be seen that the EFGT compresses fresh air (stream '1') in the air compressor ('C') before it is heated in the two heat exchangers. The hot compressed air (stream '4') is then expanded in the turbine ('E'), and a generator produces power. Since the whole process is continuous, the effluent air stream ('5'), which still has considerable thermal energy, is used to combust the feedstock in the combustion chamber ('cc'). It then becomes the hot combustion flue gas ('6') whose energy is transferred to the compressed fresh air in the two heat exchangers. After passing the heat exchangers, the combustion flue gas ('8') still contains considerable thermal energy and can be used for other heat duties, for example in CHP applications or within the process [108].

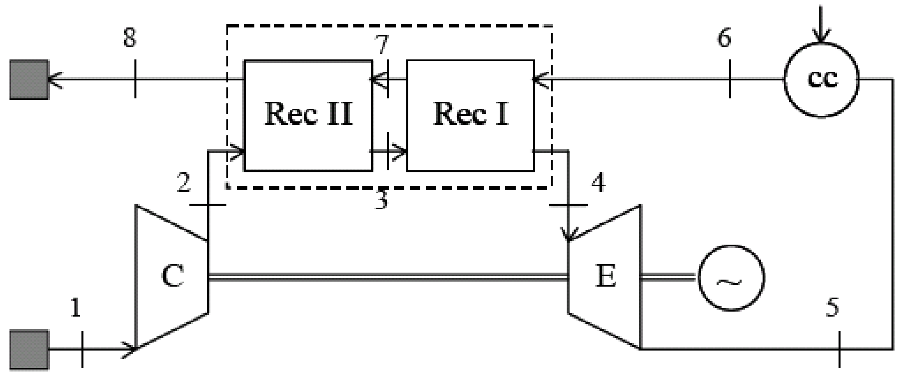

Figure 4-11: Externally Fired Gas Turbine (EFGT) Process Cycle (Source: [107]).

The efficiency of any engine design, i.e. the ratio of energy output to energy input, is strongly linked to the temperature difference between inlet and outlet. This follows from Carnot's theorem which states that the maximum thermal efficiency that a hypothetical completely reversible engine can have is the *Carnot efficiency* η_c. This efficiency can be calculated as

$$\eta_c = 1 - \frac{T_C}{T_H}, \tag{4-1}$$

with T_C being the cold side temperature and T_H being the hot side temperature [26]. Evidently, although all real engine efficiencies are below the Carnot efficiency due to not operating reversibly, their efficiency still depends on the temperature difference between their cold and hot medium. Since the cold side temperature normally is the ambient temperature and cannot be altered, their efficiency thus increases with increasing hot side temperature. For the EFGT design, the turbine efficiency as the ratio of electrical power output to feedstock energy input, depends on the temperature difference between turbine input and output, i.e. streams '4' and '5' in Figure 4-11. Due to material constraints of the metals used in the heat exchanger, its temperature is limited to around 900-1100°C. Therefore, the maximum temperature of the compressed hot air stream before entering the turbine ('4') is limited to 800-900°C [108-110].

Compared to a common combustion chamber-fired microturbine which directly uses the combustion flue gas of 900-1100°C, the amount of work which the gas can perform during expansion, and thus the process efficiency that can be achieved, is lower for EFGT designs than for combustion chamber microturbines. Efficiencies in the range of 20-25% were reported for the comparably small number of EFGT plants in operation [99].

Finally, it should be noted that advanced materials need to be applied for the high temperature heat exchangers due to the high temperature differences on the two sides of the exchanger surface, as well as the corrosivity of combustion flue gases [111]. This however has a detrimental impact on the total cost of EFGT units when compared to their directly fuelled counterparts, which may explain the limited number of EFGT plants in operation.

With regards to flexible operation of EFGT units, a study has analysed different regulation modes and the impact of their transient load operation on the process efficiency [112]. In order to adjust the turbine output power to a lower power level than nominal full power, two main operation strategies exist: *variable temperature* and *variable speed*.

The first mode adjusts the combustion chamber temperature whilst keeping the turbine speed constant. As the air mass flow is kept constant, the turbine speed will remain constant as well, and lower power outputs are achieved through a lower temperature of the air stream before expansion (stream '4' in Figure 4-11). The second mode adjusts the amount of air being expanded in the turbine, which results in a lower turbine speed. As the combustion temperature level is kept constant, the variable speed mode results in lower power outputs through less air being expanded at a constant temperature level. Figure 4-12 shows the impact of both variable temperature and variable speed mode on the process efficiency [112]. In this figure, control type 'A' depicts the *variable temperature/constant speed* mode, and control types 'B' and 'C' depict the *variable speed/constant temperature* modes of keeping either the combustion chamber temperature (type 'B') or the turbine outlet temperature (type 'C') constant.

It can be seen that *variable speed/constant temperature* is the most efficient way of operating under part-load[4]; operating down to 40-50% of nominal power only

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[4] The fact that the efficiency for control type 'B' *increases* under part-load, and thus reaches values of more than 100% of the efficiency of full nominal load, was caused by efficiency increases of the two

decreases efficiencies by less than 10% of nominal power level efficiency. Compared to *variable temperature/constant speed* mode, where the efficiency at half nominal power decreases to 60% of the efficiency of full nominal power, it can be seen that significant energy savings can be achieved by variable speed operation. It can therefore be concluded that operation of EFGT systems under variable speed can lead to very efficient part load and flexible operation patterns.

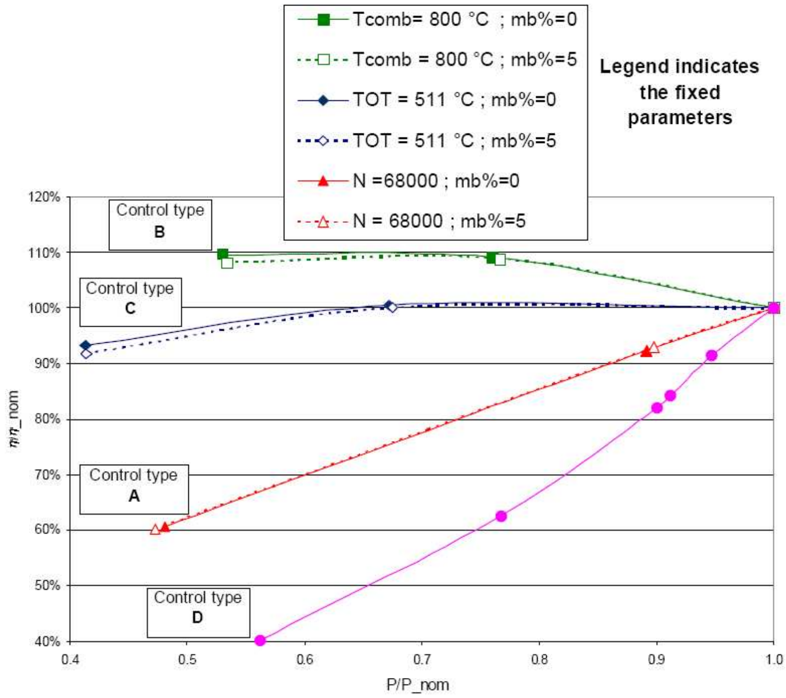

Figure 4-12: Operation Modes of Externally Fired Gas Turbines (EFGT) (Source: [112]).

However, it should at this point be remembered that all turbines in EFGT systems are coupled to heat exchangers with very high thermal inertia. The long response times of these heat exchangers therefore impact the short response time of the turbine and may result in unstable system behaviour, thus EFGT systems in general are deemed less

heat exchangers for the lower mass flow, which indicates that the EFGT system of the study was not optimised for its actual nominal power level [112].

suitable for fast load changes when compared with microturbines that are directly connected to their combustion chambers [112].

4.3.2 Fuel-Driven Generation

Those generation technologies using intermediate fuel to generate electricity are defined as *Fuel-Driven*. In comparison to the heat-driven generators, they require the feedstock to have a certain set of properties in order to operate, and therefore they require a conversion technology to transform the raw biomass feedstock into suitable fuel. Main fuel determinants are a certain minimum energy content per unit of mass or volume, a maximum content of inert substances and contaminants, and the aggregate state of the fuel. Compared to combustion based processes, fuel-driven generators in general are less flexible regarding the feedstock they can be operated with, however they are also more efficient in using their respective feedstock.

Fuels in the context of this project are liquids and gases; based on the above conversion technologies, pyrolysis and liquefaction oil as well as ethanol are examples for liquid fuels, and gasification, pyrolysis and AD gases count towards the gaseous fuel category. Furthermore, mixtures of these substances can also be used as fuel.

The main generation technologies that use fuel and fit into the scale of this project are *Microturbines* and conventional *Internal Combustion Engines*, which when being adapted for gaseous fuels are called *Gas Engines*.

4.3.2.1 Microturbines

Microturbines, similar to those used in EFGT systems described above, are small aero-derivative turbines with a comparably simple design. They consist of air compressor, combustion chamber, expansion turbine and generator, of which all but the combustion chamber are mounted on the same shaft [113, 114]. In addition, a recuperator can be used to preheat the compressed air before it enters the combustion chamber. Figure 4-13 [115] shows the schematic of a standard microturbine design, with the generator ('1'), air compressor ('5') and expansion turbine ('6') mounted on the same shaft, and the recuperator ('7') and combustion chamber ('3').

In general, a cold air stream ('2') is compressed in the air compressor ('5') and, should a recuperator be used, preheated ('7'). It is then brought in contact with the fuel in the combustion chamber ('3'), where oxidation (combustion) of the fuel occurs. Since combustion reactions lead to the release of thermal energy and to volume expansion, pressure and temperature increase and the hot compressed exhaust gas is expanded in the turbine ('6'). The turbine motion drives the generator ('1') to generate power, and the expanded exhaust gas can then be used to preheat the air in the recuperator ('7').

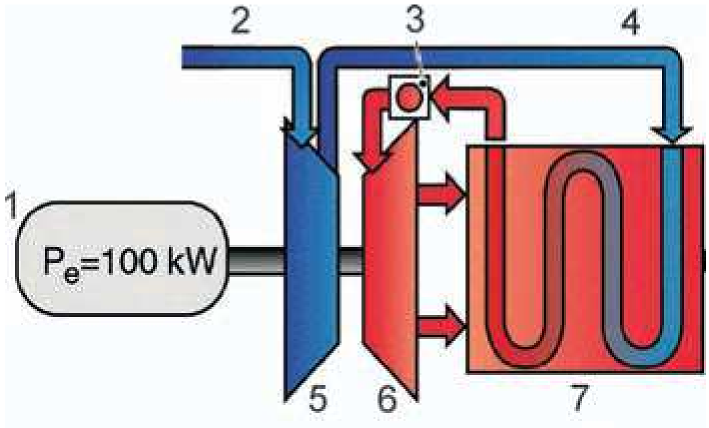

Figure 4-13: Schematic of a Recuperative Microturbine Cycle (Source: [115]).

The net amount of work that can be converted into electricity is thus the work of the expansion turbine minus the work required by the air compressor. Since the efficiency of the turbine depends on the temperature difference between turbine inlet and outlet (see also section 4.3.1.2 above), the use of a recuperator to achieve higher air temperatures significantly increases the turbine efficiency. However, its drawback is that the temperature of the gas stream leaving the microturbine is lowered from around 600°C in simple cycles to around 300°C in recuperated cycles [99, 116-118]. This means that recuperated cycles in CHP applications can only provide low level heat, such as hot water for domestic space heating, whilst industrial process heat levels cannot be reached. However, the exhaust gas stream still contains sufficient thermal energy to be used in drying processes within a plant system. Another disadvantage of the recuperator is its significant cost impact on the microturbine set [116].

Microturbines with a power range of 30-250kW$_e$ and in both power-only and CHP mode have been developed and marketed by a number of commercial suppliers [113, 114, 119, 120]. Even smaller power ranges of 1-5kW$_e$ were reported [121], however they have not reached commercial status. One example, a 30kW$_e$ model from Capstone with dimensions of 0.75m x 1.5m x 2m, is shown in Figure 4-14 [121].

Figure 4-14: Capstone 30kW$_e$ Microturbine (Source: [121]).

The CHP mode microturbine sets have an added water heater to provide hot water of around 70-90°C, whereas the power-only designs provide an exhaust gas stream of 300°C or 600°C for turbines with or without recuperation. One of the main advantages of microturbines compared to other generation technology thus is their exhaust gas stream which contains significant amounts of thermal energy, and the possibility to use this energy within the process [38, 99].

With regards to their fuel requirements, microturbines can accept both liquid and gaseous fuels, although nearly all operating units are currently run with gases, and the potential for operation on liquid fuels is mentioned as very limited due to necessary modifications [122]. For gas operated microturbines, fluctuations in the gas calorific value, i.e. different gas compositions over the course of operation, can be accommodated with relative ease, and special designs for low-calorific biomass based gases[5] are also available [59, 122]. However, microturbine operation requires the fuel stream to have a certain minimum energy content per unit of time, so when using low-

[5] Compared to the calorific value of natural gas of around 44MJ/Nm^3 [43], even biomass-based gases with a high heating value such as producer gas from pure oxygen gasification with 15-20MJ/Nm^3 still have a considerably lower energy density; see section 4.2.1.1 above.

calorific gases such as biogas and producer gas, fuel compression to a pressure of around 5bar is necessary [59, 123].

Another significant advantage of microturbines is their very low maintenance need. The use of air lubricated bearings and the compact and robust single shaft technology, together with a steady combustion process and smooth movement of the turbine results in very long maintenance cycles of up to 10,000-15,000hrs of continuous operation [113, 120, 124-126], which is a strong indicator of their applicability for remote areas and automated operation without the need to have skilled personnel available.

Due to the constant combustion process in microturbine combustion chambers, their NO_X and SO_2 emission levels are also far below those of other generation units such as reciprocating engines [115, 123, 127], which might be an important point to consider for decentralised units close to domestic customers.

Finally, the current price range of microturbine sets of around 1,000-1,900€/kW_e, albeit above that of reciprocating engines, makes them an affordable and promising generation technology. Since they have not reached market penetration yet, significant further economies of scale can be expected with continuing ongoing deployment [116, 122, 128].

The efficiencies of microturbine sets with recuperators at full load are around 25-35%, which is around 5% less than reciprocating engines of similar sizes [38, 99, 116, 129]. The impact of part-load operation on the efficiency is relatively minor, and for loads of between 50-100% of the nominal value, efficiencies lie between 80-100% of full load efficiency, which is similar to reciprocating engines [115, 116, 125, 129, 130]. Figure 4-15 [129] shows the impact of part-load operation on the microturbine efficiency, with $\dot{N}$ being the applied load as a percentage of nominal load, and $\dot{\eta}$ being the respective part-load efficiency as a percentage of nominal load efficiency.

The operation of microturbines under part-load, i.e. the adjustment of the output power, can be achieved by regulating the amount of fuel and/or the air input. Two operation modes have evolved, similar to EFGT systems as discussed in section 4.3.1.2 above: *variable-temperature* and *variable-speed* mode. In *variable-temperature* mode, the air mass flow and thus the turbine speed is kept constant and the output power is regulated by changing the combustion chamber temperature;

whereas in *variable-speed* mode, the air mass flow and thus the turbine speed is adjusted, but the combustion temperature is kept constant.

Similar to the findings for EFGT systems discussed above, variable-speed mode achieves significantly better part-load efficiencies than variable-temperature mode [115, 129, 131], as can also be seen in Figure 4-15. The main impact factor of turbine efficiency, as follows from the *Carnot efficiency* described in eqn. 4-1, is the temperature difference between turbine inlet and outlet, whilst a decrease of the volume of gas to be expanded in the turbine only has a lower impact. When operating in variable-temperature mode, this temperature difference is decreased, which drastically impacts the efficiency and explains the higher rates of efficiency decrease when compared to variable-speed mode. So although a more advanced alternator needs to be applied for variable-speed mode microturbines due to the variable turbine revolutions, variable-speed operation is the preferred option, especially for rapid and frequent load changes.

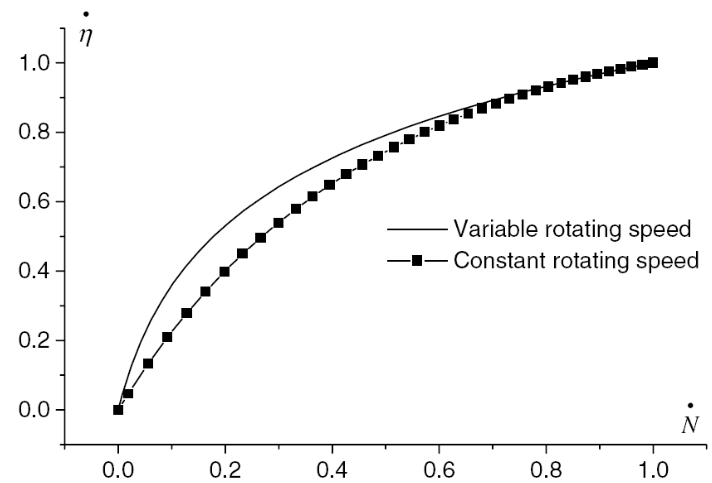

Figure 4-15: Microturbine Efficiency under Part-Load Operation (Source: [129]).

Discussing rapid and frequent load changes, which will occur when the generation unit has to follow load characteristics during flexible generation, the transient behaviour of microturbines was analysed in several independent load studies [117, 118, 132]. A microturbine can be started within 5min from cold start and within 2min from warm start, and after around 1min the electricity supply begins. Shutdowns of the turbine result in a stop of power export after around 30s, however the turbine continues to turn for several minutes before reaching complete standstill.

When applying load changes, ramping times of around 15-20s between two power output levels were achieved in grid-connected mode, and slightly better results were found for stand-alone mode. Figure 4-16 [118] shows the microturbine transient behaviour during a number of power down steps, and a similar pattern occurs for power up steps. It can be seen that the power drops very smoothly from one step to another, and after the transition periods labelled *Area 1* to *Area 3*, a steady power output at the new level is reached. In addition, the shut down sequence is also shown, and is labelled *Area 4*.

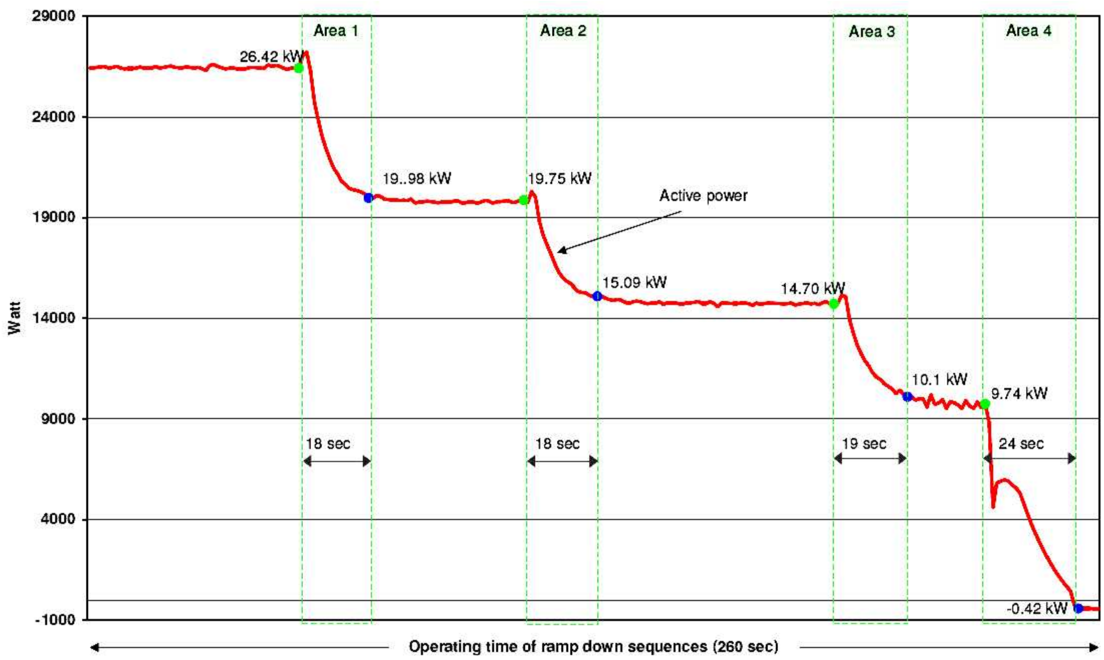

Figure 4-16: Microturbine Power Ramping Sequence (Source: [118]).

It can therefore be concluded that microturbine sets are suitable engines of a fitting size for remote and automated applications, and their relatively robust efficiency and transient behaviour under part-load also enables them as a technology for flexible generation.

4.3.2.2 Internal Combustion Engines and Gas Engines

Internal Combustion Engines (ICE) are the main conventional fuel-driven generation technology for small scale power, and prior to the development of microturbines were the only option for decades [125]. They follow a cycle well-known from conventional automotive engines, where air is compressed within a cylinder, mixed with fuel and then either ignited by a spark or self-ignited due to the high pressure. The combustion process leads to an increase in volume and pressure, and through expansion the combustion flue gases provide work on a piston. By connecting the pistons to a crankshaft, their linear motion can be converted into rotational motion, and whilst automotive ICE use this motion to drive automobiles, power generation can be achieved by coupling the engine to a generator. Figure 4-17 [6] shows a schematic of the working cycle for a conventional four-stroke spark ignition engine.

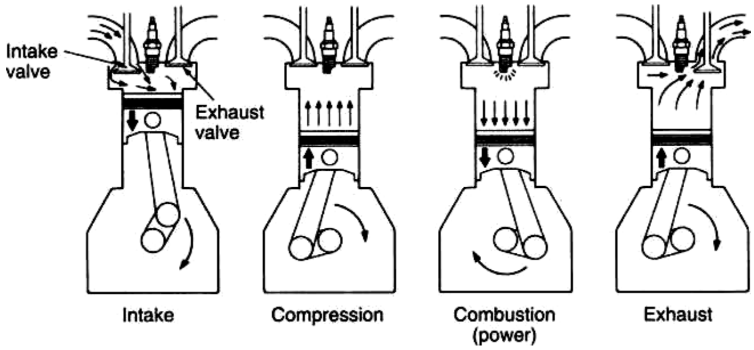

Figure 4-17: Schematic of Four-Stroke Spark Ignition Engine Cycle (Source: [6]).

ICE for power, comparable to their automotive counterparts, are normally operated with liquid fossil fuels such as petrol and diesel, whilst biomass-based fuels such as ethanol or pyrolysis oil can also be used. The adoption of gaseous fuels in ICE technology has created *Gas Engines* (GE), and they can be operated on gases such as natural gas, producer gas or biogas [125].

ICE and GE for power generation have strongly benefited from the development of their automotive counterparts and have been in a commercial stage for decades. They are available in a broad range of scales from a few kW_e up to several MW_e and have significant economies of scale and cost advantages over other generation technology [31, 125, 133]. Both ICE and GE are able to run on fuels or fuel mixtures which fluctuate in quality, so they are well-suited especially for small scale biomass conversion processes [125, 134].

During their operation cycle, a significant share of the thermal energy of combustion however is transferred to the piston and cylinder material and is thus not productively used by the engine. In addition, friction between cylinder and piston results in dissipation processes, which further increases the material temperature. Therefore, cooling of the material through external air or water streams becomes necessary. However, since this heat energy is separated from the flue gas that exits the engine, the exhaust gas temperature of ICE and GE of around 80-100°C is rather low when compared to turbines [38, 128]. This and the low temperatures from the engine cooling systems make further use of this heat energy very difficult.

ICE and GE achieve full nominal power efficiencies of around 30-40% [38, 98, 99, 128, 135, 136], which is the highest value of any generation technology. They are well-suited to be operated under part-load, and the impact of part-load operation on their efficiency is shown in Figure 4-18 [136], with $\eta_{i\text{-}net}$ being the net efficiency. The part-load efficiency has similar characteristics to the respective values of microturbines as depicted in Figure 4-15, however on a higher level. Finally, ICE and GE transient operation characteristics are similarly favourable. Power output changes can be achieved very quickly, and fluctuating loads can be accommodated with ease, hence in a combination with batteries ICE were the standard solution for emergency gen-sets. It should however be noted that a trend of replacing ICE with microturbines in emergency gen-sets began recently, which seems to be caused by the higher maintenance levels necessary for ICE when compared to microturbines [119, 120, 126].

When operating ICE and GE with biomass-derived fuels, special attention needs to be drawn to their oil lubrication. To minimise the friction between piston and cylinder wall, the surfaces are lubricated. However, hydrogen sulphide (H_2S), a gaseous by-product of AD, is highly soluble in lubricants, so for gas engines operated on biogas from AD, frequent lubrication changes become necessary unless the biogas is cleaned of H_2S beforehand. Maintenance cycles for lubricant and filter changes as frequent as every 500hrs are mentioned [48, 125, 126, 137, 138], which severely hampers the applicability of gas engines for biogas operation especially in rural and remote areas, where they are intended to continuously run as the single generation unit, and where skilled personnel are not on site [48, 126].

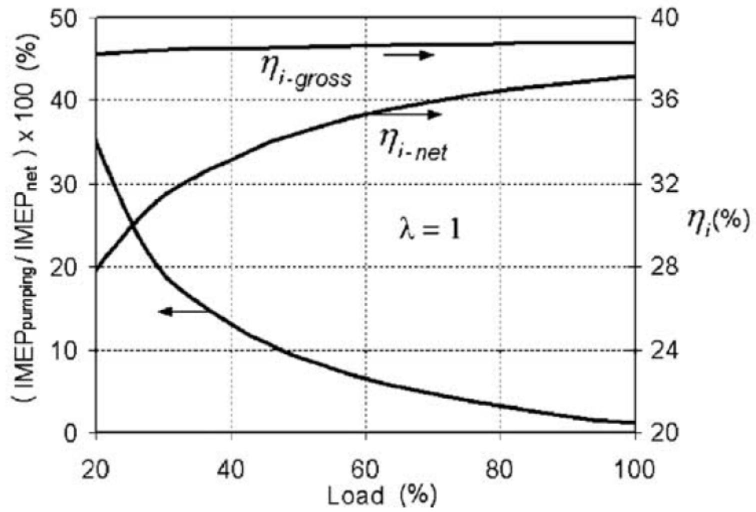

Figure 4-18: ICE/GE Efficiency under Part-Load Operation (Source: [136]).

Finally, the ignition processes that occur within the cylinders of ICE and GE are abrupt, so fuel combustion is incomplete and pollutant emission levels, mainly in terms of CO and NO_X, are significantly higher than those of microturbines with their very clean and complete combustion process [127]. Differences in emissions of up to an order of magnitude between ICE/GE and microturbines were reported [123, 130], a fact which may need to be taken into consideration with regards to emission legislation or when intending to operate them in remote areas close to residential customers.

4.4 Technology Comparison and Ranking

After the above sections provided the results of an extensive literature and market analysis undertaken for each available conversion and generation technology, a final decision needs to be made to select one or several technologies for the intended plant design. This decision-making process and its results will be described in this section.

When having to decide between different alternatives, a proven strategy is to establish a set of decision criteria and then to compare to what extent each alternative meets these criteria. The result of this is a ranking of the alternatives. This methodology is known as multi-criteria decision-making or multi-criteria decision analysis (MCDM/ MCDA), and has itself been subject to extensive research and application to widely varied decision making problems [6, 139].

As an example, Table 4-V shows a given problem with four main criteria (*I-IV*), to which three different alternatives (*A-C*) exist. Each alternative fulfils each criterion to some extent, which is expressed by the four fulfilment factors $F_1(A\text{-}C)\text{-}F_4(A\text{-}C)$. Each criterion is then assigned a ranking or weighing factor ($W_1\text{-}W_4$) that expresses the relative importance of this criterion when compared to the other criteria. A decision can then be made by calculating the overall fulfilment functions for each alternative. The fulfilment function for alternative *A* (*FF(A)*) can be calculated as

$$FF(A) = W_1 \cdot F_1(A) + W_2 \cdot F_2(A) + W_3 \cdot F_3(A) + W_4 \cdot F_4(A), \qquad (4\text{-}2)$$

and similarly for the other alternatives *B* and *C*. Comparing the fulfilment functions for each alternative, the best solution for the problem is the solution with the highest fulfilment function.

Table 4-V: Example Multi-Criteria Decision-Making Matrix.

	Alternative A	Alternative B	Alternative C
Criterion I	$W_1 \cdot F_1(A)$	$W_1 \cdot F_1(B)$	$W_1 \cdot F_1(C)$
Criterion II	$W_2 \cdot F_2(A)$	$W_2 \cdot F_2(B)$	$W_2 \cdot F_2(C)$
Criterion III	$W_3 \cdot F_3(A)$	$W_3 \cdot F_3(B)$	$W_3 \cdot F_3(C)$
Criterion IV	$W_4 \cdot F_4(A)$	$W_4 \cdot F_4(B)$	$W_4 \cdot F_4(C)$

A similar process was applied to the problem of choosing the conversion and generation technologies for the plant in this project. First, a set of criteria was developed on the basis of the aims and objectives of the plant in this project, and then weighing factors were assigned for each criterion.

Assigning the weighing factors for each criterion is an important step in the decision making process: unrealistically high weighing factors for one criterion lead to an over-representation of this criterion in the final decision and can be used to manipulate the decision towards a favoured alternative. Since the developed set of criteria of this project was based on its aims and objectives, there is no reason to rank one criterion higher than another; all criteria are of equal importance, hence they were all assigned the same weighing factor (i.e. W_1-$W_4 = 1$).

Thereafter, each technology was assigned values for its fulfilment factors with regards to how it fulfils the respective criterion in comparison to the other alternatives in its group. The following values were used for the fulfilment factors:

$F = 0.1$ means "alternative fulfils criterion significantly below average"

$F = 0.3$ means "alternative fulfils criterion below average"

$F = 0.5$ means "alternative fulfils criterion on average"

$F = 0.7$ means "alternative fulfils criterion significantly above average"

$F = 0.9$ means "alternative fulfils criterion significantly above average"

The following sections will provide the comparison and ranking for both conversion and generation technologies, and the results obtained.

4.4.1 Conversion Technology Comparison and Ranking

On the basis of the aims and objectives of the plant as outlined in chapter 2 above, a set of criteria was defined for the conversion technologies as follows:

- Conversion level: the conversion level represents what percentage of biomass feedstock will be converted into fuel, which directly influences reactor volume and throughput times as well as the amount of feedstock necessary to receive a given amount of fuel.
- Simplicity: since the plant is to be designed for automated operation and likely for remote locations with a minimum of required work and interaction with skilled personnel, the simplicity of the technology is of key importance. This also includes factors such as robustness and ease of operation.
- Plant cost: although most of the technologies covered in this project have reached some level of maturity, it should be noted that plant cost in general will be relatively high when compared to fossil fuel plants. However, as will be covered in chapter 9, plant costs are not the pivotal factor for this project.

- Conversion time: this factor will represent the necessary retention time of biomass feedstock in the conversion reactor until the conversion rate has reached the conversion level. This factor again impacts the volume and size of the reactor as well as the energy efficiency of the technology through heat losses which increase with time, which is covered in more detail in section 6.2.
- Applicability to scale: the applicability of a technology to a given scale is a critical criterion. As was mentioned above, some designs are only suitable for a given minimum scale, whereas other designs were developed specifically for use at maximum scales. Since the plant for this project is aimed at village-scale power generation, this factor represents the efficiency of the technology when applied to such village-scale compared to its efficiency for the nominal scale it was initially designed and optimised for.

Table 4-VI provides a short summary of how each of the dry feedstock conversion technologies fulfils each criterion, and the resulting values of the fulfilment functions.

Table 4-VI: Dry Feedstock Conversion Technology Criteria Matrix.

Criterion	**Gasification**	**Pyrolysis**	**Liquefaction**
Conversion Level	*$F_1 = 0.7$* High conversion levels, up to 80-90% of feedstock intake	*$F_1 = 0.5$* Medium conversion levels due to both gas and oil phase, but possible to adjust	*$F_1 = 0.5$* Medium conversion levels, around 20-50% of feedstock intake
Simplicity	*$F_2 = 0.5$* Very simple reactor design for fixed bed, robust operation with uniform feedstock	*$F_2 = 0.5$* Simple reactor design for rapid pyrolysis, robust operation with uniform feedstock	*$F_2 = 0.1$* Complex pressurised reactor design and safety issues due to high pressure levels
Plant Cost	*$F_3 = 0.5$* Average reactor costs due to simple design	*$F_3 = 0.5$* Average reactor costs due to simple design	*$F_3 = 0.3$* Higher costs due to pressurised equipment
Conversion Time	*$F_4 = 0.5$* Conversion time in the order of up to 1min for fixed bed reactors	*$F_4 = 0.7$* Conversion time in the order of several seconds for rapid pyrolysis	*$F_4 = 0.5$* Conversion time in the order of one to several minutes
Applicability To Scale	*$F_5 = 0.9$* Fixed bed reactors are highly applicable to small scales	*$F_5 = 0.5$* Aimed at medium to larger scale, but functional at small scale	*$F_5 = 0.1$* Aimed at large scale due to sophisticated equipment and design
Fulfilment Function	***FF(Gas)=3.1***	***FF(Pyr)=2.7***	***FF(Liq)=1.5***

From this summary follows that gasification is the best option for dry feedstock conversion, followed with some distance by pyrolysis and liquefaction. Therefore, a decision was made to incorporate a fixed bed co-current gasifier in the plant design for the handling of dry feedstock.

Table 4-VII provides a similar overview of wet feedstock conversion technology properties and their respective fulfilment functions.

Table 4-VII: Wet Feedstock Conversion Technology Criteria Matrix.

Criterion	Anaerobic Digestion	Fermentation
Conversion Level	$F_1 = 0.5$ Medium conversion levels, around 30-60% of digestible material	$F_1 = 0.5$ Medium conversion levels, around 50% of fermentable material
Simplicity	$F_2 = 0.9$ Very simple digester design, storage tank and mixing unproblematic	$F_2 = 0.3$ Relatively simple fermenter tank design, but post-distillation necessary
Plant Cost	$F_3 = 0.9$ Very low plant cost due to simple design, low-cost digesters available	$F_3 = 0.3$ Average plant cost for fermenter tank, but costly distillation equipment
Conversion Time	$F_4 = 0.3$ Acceptable conversion rates within 15-20 days of mesophilic digestion, faster for thermophilic	$F_4 = 0.7$ Conversion within 1-3 days for sugar-rich feedstock, longer for starch feedstock
Applicability to Scale	$F_5 = 0.9$ Applied to farm scale for decades for sludge treatment, use for power well-tested	$F_5 = 0.3$ Aimed at larger industrial scale such as alcohol distilleries due to distillation equipment
Fulfilment Function	***FF(AD)=3.5***	***FF(Fer)=2.1***

It can be seen that for wet feedstock conversion, anaerobic digestion is significantly ahead of fermentation. Therefore, it was decided to incorporate a mesophilic anaerobic digester tank for the treatment of wet feedstock. Since both anaerobic digesters and gasification reactors produce a gaseous fuel, fuel storage and handling can also be achieved with more ease.

The feedstock demand and supply for both the gasifier and the anaerobic digester will be discussed in detail in section 6.2.5, however it was mentioned before that one critical objective will be to continuously source sufficient feedstock locally. It was thus decided to incorporate both wet and dry feedstock conversion technologies to ease feedstock sourcing through a plant that can convert a diverse range of available biomass; and since both gasification reactors and anaerobic digesters can be set up for small scale plants, the scaling of the system, which will be described in detail in section 6.2, should not provide major obstacles.

4.4.2 Generation Technology Comparison and Ranking

After having decided which conversion technologies to use for the plant, a similar decision matrix will be used for the available generation technologies. A relevant set of criteria was developed on the basis of the project objectives as follows:

- Full load efficiency: The full or nominal efficiency is the ratio between fuel energy input and power output[6]. The full/nominal efficiency is an important indicator since it impacts the amount of fuel necessary for each unit of power, so high efficiencies will reduce the fuel input and therefore the amount of fuel necessary.
- Part load efficiency: Since the plant for this project is intended to be the single generation unit to meet fluctuating demand, it will have to operate on load levels below full nominal power output. This will be discussed in more detail in the modelling and simulation chapters, however part load operation will be a crucial criterion for a successful ongoing operation of the plant. Therefore, the efficiency of operating at half nominal load, i.e. at 50% of the maximum full load, was included as a separate criterion.
- Load flexibility: Operating a generator at different load levels impacts its efficiency, however some types of generator can easily be operated between full and nearly no output, whilst others may not be able to operate at different output levels at all. Therefore, load flexibility and load efficiency behaviour are separate parameters, and since the plant for this project will have to adjust its output power frequently in order to follow the fluctuations in demand, load flexibility is another crucial parameter.
- Investment cost: Apart from fuel efficiency, which defines the necessary amount of fuel and thus the fuel costs to obtain a unit of output power, the

[6] See also section 9.3 where the process efficiencies will be discussed in more detail.

investment costs of the generator, although accrued only once for each plant over the life time of the generator, is a significant factor in deciding for a technology that is intended to provide relatively few customers with power. However, this cost critically depends on the estimated life time of the generator, since higher investment costs can be tolerated for very long expected life times of the generator. The costs are thus compared on a per-kW basis over the lifetime of the different technologies.

- Maintenance: Besides investment and fuel costs, maintenance costs are another crucial cost factor that can impact the decision for or against a technology. Maintenance includes the outage time, i.e. the amount of time necessary for regular repair or replacement of plant parts, as well as the cost of replacement parts. It also includes the general maintenance that is necessary during operation, which means that fully automated operation over long periods of time is incentivised over operation which requires personnel on site.
- Emissions: The emission level of a generator is another important factor, especially for plants that are intended to provide power close to residential customers. A comparison of the main emissions (NO_X and CO) is thus included in this category.
- Development level: Finally, the development level is a criterion that examines whether the technology has matured, or whether it still is in a very early stage of development. Since the plant will be expected to operate autonomously and under real life conditions, technology which has operated for decades will be incentivised over technology which is still in the laboratory testing stage.

Similarly to Table 4-VI/VII above, the following tables provide a short summary of each generation technology for each criterion, and the resulting fulfilment function values.

Table 4-VIII: Combustion-Based Generation Technology Criteria Matrix.

Criterion	Stirling Engine	Externally Fired Gas Turbine
Full Load Efficiency	*$F_1 = 0.3$* Relatively low efficiency of 20-25%	*$F_1 = 0.3$* Relatively low efficiency of 20-25%
Part Load Efficiency	*$F_2 = 0.1$* Significant efficiency decrease when operating at less than 90% load	*$F_2 = 0.7$* Half load efficiency still reaches ~90% of full load efficiency
Load Flexibility	*$F_3 = 0.1$* Low flexibility due to combustion-based load regulation; high thermal inertia make fast load changes impossible	*$F_3 = 0.3$* High thermal inertia in heat exchangers hamper load flexibility; fast load changes (by-pass mode) impact efficiency strongly
Investment Cost	*$F_4 = 0.1$* High price technology due to high pressure engine and sophisticated heat exchangers	*$F_4 = 0.3$* Above average cost due to need for sophisticated high-temperature heat exchangers
Maintenance	*$F_5 = 0.7$* Very low maintenance technology, up to 8-10,000 hours of continuous operation, but costly spares due to pressurised engine and high temperatures	*$F_5 = 0.7$* Very low maintenance technology, up to 8-10,000 hours of continuous operation, heat exchanger replacement can be costly
Emissions	*$F_6 = 0.7$* Emissions depend on combustion technology, low-emission and clean-burning furnaces exist	*$F_6 = 0.7$* Emissions depend on combustion technology, low-emission and clean-burning furnaces exist
Development Level	*$F_7 = 0.3$* Very few operational engines, still in relatively early stage	*$F_7 = 0.5$* High-temperature heat exchangers still critical, whilst turbine technology already well-developed
Fulfilment Function	***FF(SE)=2.3***	***FF(EFGT)=3.5***

Table 4-IX: Fuel-Based Generation Technology Criteria Matrix.

Criterion	Internal Combustion Engine	Microturbine
Full Load Efficiency	*$F_1 = 0.9$* Very high efficiency, up to 30-40%	*$F_1 = 0.7$* Above average efficiency of between 25-35%
Part Load Efficiency	*$F_2 = 0.9$* Very good part load efficiency, half load reaches 90-95% of full load efficiency	*$F_2 = 0.7$* Good part load efficiency, half load reaches up to 90% of full load efficiency
Load Flexibility	*$F_3 = 0.7$* Very good load flexibility, fast load changes possible	*$F_3 = 0.7$* Very good load flexibility, fast load changes possible
Investment Cost	*$F_4 = 0.9$* Relatively cheap due to decades of maturation, proven technology	*$F_4 = 0.7$* On the brink of market penetration and maturation, acceptable price level
Maintenance	*$F_5 = 0.3$* Regular maintenance necessary, frequent lubrication exchange, but very cheap spare parts	*$F_5 = 0.9$* Very low maintenance technology, up to more than 10,000 hours of continuous operation, few moving parts, no lubrication necessary
Emissions	*$F_6 = 0.3$* High emission levels due to incomplete combustion of fuel in piston	*$F_6 = 0.9$* Very low emission levels due to continuous and clean combustion of fuel
Development Level	*$F_7 = 0.9$* Completely mature technology, decades of development	*$F_7 = 0.7$* Reaching market penetration, turbine technology well-developed
Fulfilment Function	***FF(ICE)=4.9***	***FF(MT)=5.3***

The results show the microturbine leading but closely followed by internal combustion engines, whilst the two combustion-based technologies Stirling and EFGT fall behind significantly.

Since the two chosen conversion technologies produce fuel gases and microturbines can be operated efficiently and effectively on gases, it was decided to apply a microturbine as the generation unit of the plant.

It can thus be concluded that those technologies which appear most suitable for the intention of this project were revealed through an evaluation of available biomass conversion and generation technology in the first section of this chapter, and after ranking the different technologies of each category in this section.

In order to obtain maximum feedstock flexibility it was decided to apply a combination of both dry and wet feedstock treatment to convert raw biomass into a gaseous fuel, by means of a co-current fixed bed gasifier and a mesophilic anaerobic digester. The fuel gas mix of producer gas and biogas will then be used to operate a flexibly-running microturbine as the generation unit of the plant to supply power to the customers.

On the basis of this technology choice, the detailed plant model will be developed in the following chapter.

5 Plant Description and Modelling

After all available biomass-based power technologies have been described and evaluated in the previous chapter and a decision has been made on which technologies to employ for the plant system, this chapter will provide a description of each sub-unit and the combined plant system. It will provide information on how the units are connected in order to create an efficient plant system. After this description, the simulation model of this plant will be developed and described in detail; this model will then be employed for extensive operational and optimisation simulations in the later chapters.

5.1 Plant Description

The plant system consists of the following main sub-units: a co-current fixed-bed gasifier; a mesophilic anaerobic digester; a microturbine as the generation unit; and a fuel storage system. Additionally, an electric heater and a feedstock dryer will provide heat for drying the feedstock for gasification. Whilst the feedstock dryer will use process heat, the electric heater also functions as the power sink of the plant in order to match supply and demand.

The aim of this plant is to continuously provide power to a group of customers, hence the plant will be operated electricity-led, which means that the turbine output power will be the main output variable; this output power will depend on the power demand of the customer group and will be changed during flexible operation of the plant. The process heat of the plant will be employed internally in order to efficiently use the energy of the feedstock. The alternative to electricity-led operation would be heat-led operation, where the provision of heat to the customers would be the main intention and the operation would follow the heat demand of the customers. This operation mode however cannot be applied to a plant whose main intention is continuous power provision [140], therefore it was decided to instead use as much heat as possible within the plant processes.

Since the plant is intended for remote off-grid operation, the absence of skilled personnel on site should not be an issue, so a high level of autonomous operation will be aimed for. The plant design offers the advantages of long maintenance cycles and good response to load changes, and a microturbine can be operated by remote or preset control, which enables autonomous plant operation.

The proposed plant will be required to continuously supply power to the group of customers, whose demand will result in a load profile somewhat similar to that shown in Figure 1-4. This will be discussed in more detail in chapter 7, however a fluctuating load profile has to be expected, and since the plant is intended for off-grid power supply, it will need to level out the demand fluctuations by means of flexible generation.

Conventional off-grid power solutions employ batteries to instantly cover a sudden load change and to allow sufficient time for the generator to switch to an adjusted load level. However, batteries as well as other electricity storage result in significant maintenance efforts, and considerable energy losses occur, especially when used in very frequent charging and discharging cycles [5, 141]. Instead of applying large scale batteries, this plant will be designed to run on a number of comparably steady load steps, between which the plant can be adjusted depending on the demand. This however requires a surplus of electricity generation at each unit of time, which is a necessary operation constraint to always ensure full supply of the demand of the domestic customers, which to some extent remains unknown. Generation will always be considerably higher than the forecasted load, and electricity sinks in the form of an electric feedstock heater and a fuel gas compressor will immediately 'use up' all surplus electricity so that the system generation equals the system demand.

The electric feedstock heater however will also result in better gasification efficiencies due to providing feedstock with a lower moisture content, and thus a better quality intermediate fuel gas will be produced. This gas can then be stored more efficiently than the electricity surplus.

Figure 5-1 shows a flow chart of the plant design, and the main parts are described in the following sections, referring to the numbering and stream names as shown in the flow chart.

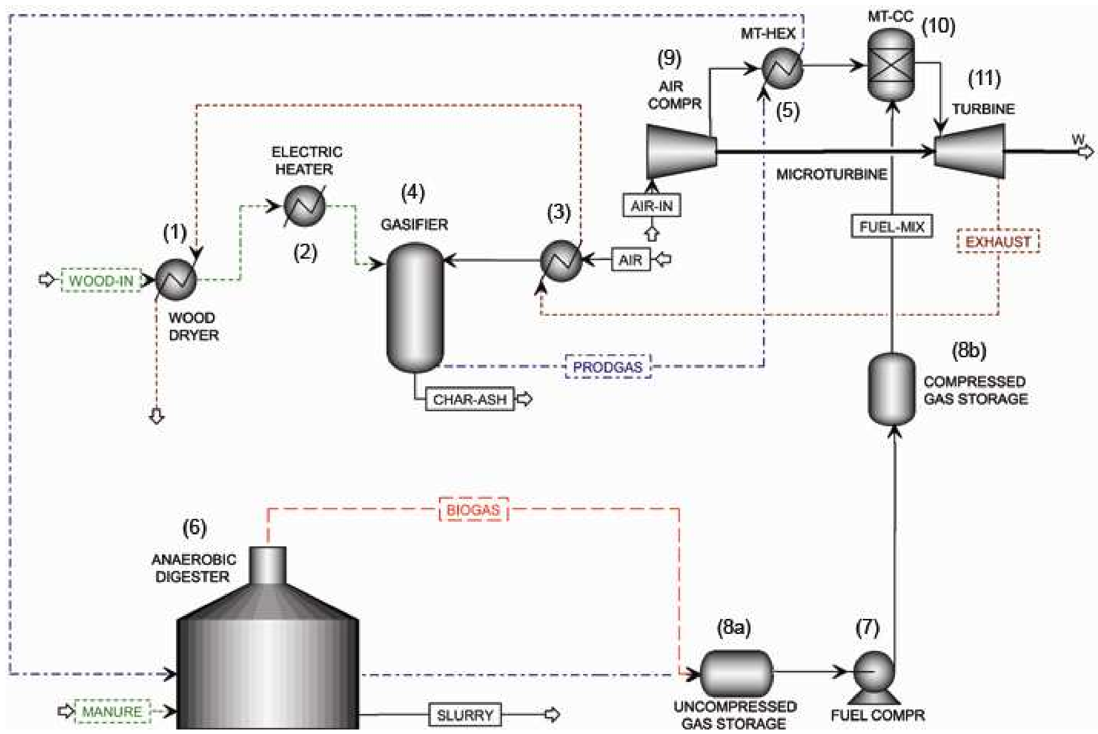

Figure 5-1: Plant Flow Chart.

5.1.1 Gasifier

A simple fixed bed co-current gasification system is used to process waste wood and other suitable dry biomass feedstock and to convert it into producer gas. After the initial feedstock pre-treatment such as sorting and shredding, which are processes that can be done in intervals after harvest or before storing the processed feedstock, the biomass (‘*WOOD-IN*’) will be dried in the wood dryer (‘1’), which uses remaining heat of the microturbine exhaust gas stream (‘*EXHAUST*’). An exit moisture content of around 10% will be aimed for during the drying process. After passing the wood dryer, the feedstock will be fed into the electric heater (‘2’) which is operated as the demand/supply balancing tool within the plant, as discussed above. This means that the electric heater will run on very fluctuating power levels, which it transforms into heat to dry the feedstock further.

The wood dryer will always ensure a certain maximum moisture content of the feedstock before it enters the electric heater. Therefore, the irregular activation of the electric heater may result in a variable moisture content of the exiting feedstock, but limited to the maximum set in the wood dryer. The activation of the electric heater however will positively affect the gasification yield, as lower moisture contents result in producer gas of higher quality. The electric heater therefore uses the excess electricity to increase the gasification efficiency. Since varying biomass feedstock moisture contents can be processed in downdraft gasifiers, the fact that the final moisture content may fluctuate does not pose a problem to the gasification process.

In case of it being necessary, such as for start-up of the gasification process, part of the dried biomass feedstock as well as unconverted biomass char can be burnt in the gasifier combustion chamber ('3') to provide sufficient heat levels for a continuous high temperature gasification agent stream ('*AIR*'). During ongoing operation, the microturbine exhaust gas stream ('*EXHAUST*') will provide this heat. The hot gasification agent, together with the feedstock, will then be inserted into the gasifier ('4'), where the gasification reactions occur and where the biomass is decomposed into char and tars (i.e. unconverted biomass), ash and producer gas.

The producer gas will leave the reactor as a high temperature stream ('*PRODGAS*'), and it will be used to preheat the compressed turbine air in the microturbine heat exchanger ('5'). Afterwards, the producer gas will have a relatively low temperature, however it will still be hot enough to provide sufficient heat for the anaerobic digester ('6').

5.1.2 Anaerobic Digester

The anaerobic digestion unit ('6') will process highly diluted farm waste such as livestock manure or food and vegetable waste. A simple plug-flow or steady-flow mesophilic digester design will be employed to ensure low cost and ease of operation. Enough exhaust heat will be available from the producer gas stream to provide the digester temperature level of ~35°C, as will be shown in the simulations in section 7.2.

The manure ('*MANURE*') will be fed into the reactor, kept for a period of 20 days and converted into a methane/carbon dioxide biogas mixture ('*BIOGAS*') and a liquid effluent ('*SLURRY*'). Whereas the liquid effluent can be used as a fertiliser or for soil improvement, the biogas stream will be mixed with the producer gas stream as they enter the uncompressed gas storage tank ('8a') as part of the gas storage system.

The power that is necessary for mixing the reactor and for pumping in the raw feedstock as well as pumping out the effluent is calculated as a percentage of the total energy demand of the reactor, as detailed in section 6.2.1, and these values are included in the simulation model of the reactor.

5.1.3 Gas Storage System

The gas storage system plays a key role within the plant. The producer gas/biogas mixture will be the main energy vector for the plant, so the storage system needs to be sufficient in size to be able to cover peak load demands.

The two gas streams first enter the uncompressed gas storage (‘8a’). Both conversion technologies are operated continuously, so the gas flow into the uncompressed storage will also be continuous. Since a certain minimum energy flow needs to be provided for the microturbine, the gas stream needs to be compressed, which is done by the gas compressor (‘7’). However, it is also used as another tool to match supply and demand within the plant, and it is operated on variable power. Its power level, similar to the electric heater power, depends on the difference between generation and demand, as will be described in detail in section 7.2.4. This means that depending on the power available for the gas compressor, part of the combined producer gas/biogas stream will be compressed to a pressure level slightly higher than needed for the turbine. This compressed gas stream will then enter the compressed gas storage (‘8b’) where it is kept before needed by the turbine.

Since biogas is normally saturated with water vapour when leaving the digester, a compressor with the ability to handle gas/vapour streams needs to be employed. To prevent corrosion and fouling, the gas stream needs to be relatively dry before it enters the microturbine. It has been reported that water precipitation takes place when storing compressed biogas due to the temperature difference [48], so the compressed storage will allow the precipitation of water before the microturbine is operated on the gas mixture. Another advantage of the compressed storage is the immediate availability of compressed fuel gas in case the turbine output needs to be increased, whilst uncompressed gas would first need to be compressed, and this would result in a time lag between higher demand and higher production. Since compressed storage facilities do not result in significant losses and their cost impact is not prohibitive [48], it was chosen to apply a compressed gas storage system for this plant design.

5.1.4 Microturbine

The microturbine as the generation unit of the plant runs on the gas mixture (‘*FUEL-MIX*’) to generate electricity. In the first step, air of ambient temperature (‘*AIR-IN*’) is compressed in the microturbine compressor (‘9’). This compressed air will then be preheated in the heat exchanger (‘5’) that uses the high thermal energy of the producer gas stream. Afterwards, the hot compressed air enters the microturbine combustion chamber (‘10’), where it will be mixed with fuel gas released from the gas storage system. It will then be burnt and the hot exhaust gases will be expanded in the turbine (‘11’), generating power by means of an alternator. The turbine exhaust gas (‘*EXHAUST*’) has a considerable temperature level of around 600°C, which will be used in the gasification unit as described earlier.

The microturbine will be in the size range of ~100kW$_e$ output, depending on the maximum load from the group of customers, and it will be operated on variable speed mode in load steps between half- and full nominal load. As mentioned earlier, the turbine cannot immediately follow a load change, but needs to adjust to the new speed level over several seconds. Therefore, the turbine output will not be changed continuously but it will be operated on a number of comparably steady load steps, and by ensuring that the turbine generation always exceeds the load demand, electricity supply can be secured at each unit of time. This will be described in the load simulations in chapter 7.

5.2 Plant Modelling

Following the description of the plant design in the previous section, this section will describe a detailed simulation model of this plant. This model was developed in order to check the feasibility of the plant system and to perform simulation studies on the operation and optimisation of the plant, which will be described in later chapters.

5.2.1 Software Description and Suitability

The plant modelling and simulation was undertaken in the Aspen Plus chemical process simulation software package. This simulator provides a modular system in which a number of chemical models can be assigned for each part of a plant. This software was chosen because of its availability, its frequency of use in industry and since it provides a large number of power and chemical engineering models which are beneficial for creating a realistic model. Using a proven industrial process engineering software package to model reaction kinetics, mass and energy transfer and the like enables the use of a large set of standard models and properties. As Aspen Plus also provides a high level of adjustment options through parameterisation, the level of detail can easily be adjusted as necessary.

The Aspen Plus simulation environment provides and computes steady state process models. Both biomass conversion technologies adopted in this plant will be operated in a continuous and steady manner in order to obtain consistent fuel gas qualities. Therefore, a steady-state modelling of those processes is coherent and has also been recommended in literature [142].

The generation part of the plant will need to cope with fluctuating loads since it will be the single power source of the system. It therefore will need to adjust its output to accommodate differences in demand over time.

As mentioned earlier, microturbine operation however also requires a certain amount of steadiness, as the turbine needs around 20-30s to adopt a new output power level [118]. The plant design thus arranges for the microturbine to be operated on a number of power steps, and the power sinks will accommodate fluctuations in-between those power steps. The microturbine dynamic operation can therefore be modelled as a sequence of steady-state operations on different power levels.

An overview of the complete plant system as modelled in Aspen Plus is shown in Figure 5-2, and each main subsection is described in detail in the following sections. In addition, Appendix B provides the programming code for this model and can thus be used to rebuild the model.

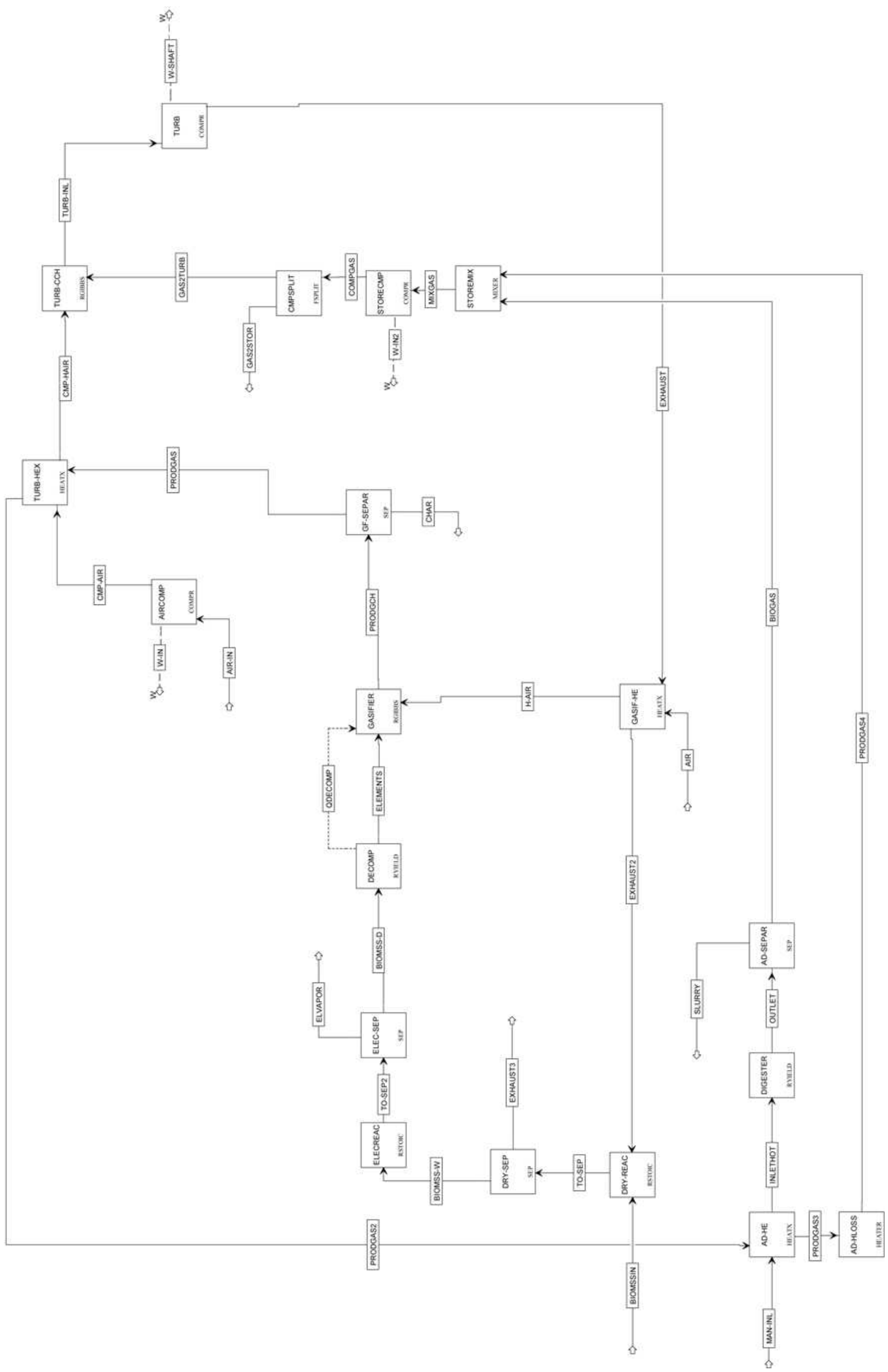

Figure 5-2: Plant Flowsheet Model in Aspen Plus.

5.2.2 Gasifier

The gasifier was modelled in a two-step approach, as shown in Figure 5-3, which means that two main processes were employed to represent it in the model. Biomass in general cannot be modelled within Aspen Plus as a normal component stream as it is not a conventional chemical substance, but a homogenous mix of a large number of different organic molecules, as discussed in section 4.1.1 above. However, Aspen Plus accommodates the handling of non-conventional components, which can be defined and modelled as necessary. Therefore, the dry biomass feedstock in the form of wood chips is modelled as a non-conventional material stream by using its proximate and ultimate analysis values, which were provided in Table 4-I and Table 4-II, respectively.

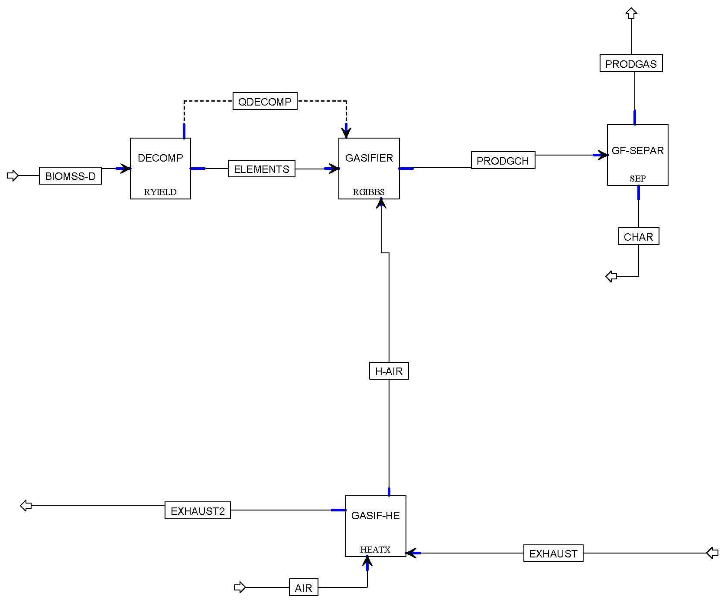

Figure 5-3: Gasifier Flowsheet Model.

In the first step, biomass chips are decomposed into their main compository elements, as expressed by the following overall pseudo-formula

$$CHONS \rightarrow C + H_2 + O_2 + N_2 + S \tag{5-1}$$

The stoichiometric decomposition is accommodated in the *DECOMP* simulation block. The resulting elementary stream *ELEMENTS* is then converted into a producer gas mixture in the *GASIFIER* block. Air is used as the gasification medium, and first passes a heat exchanger (*GASIF-HE*) that uses the turbine exhaust heat stream to preheat the air. A hot inlet stream/cold outlet stream temperature difference approach of 10K was chosen, and an air/fuel ratio of 1.5 based on dry, ash-free biomass has been implemented; these values are in accordance with literature and have proven to provide realistic results [23].

The preheated airstream *H-AIR*, together with the decomposed biomass stream, is converted into producer gas, a gas mainly consisting of nitrogen, carbon monoxide, hydrogen and carbon dioxide. For this conversion, an *RGIBBS* reactor type is used, which calculates the product composition based on the minimisation of Gibb's free energy [143]. The Gibb's free energy of a system is a thermodynamic potential that measures the maximum amount of non-expansion work available from a system. It can be described as

$$G = H - TS \,. \tag{5-2}$$

For a system where changes such as reactions occur, a negative difference in Gibb's free energy between two states 1 and 2 – before and after the reaction – leads to a more stable, i.e. favourable, state of the system, and can be expressed as

$$\Delta G = G_2 - G_1 < 0 \,. \tag{5-3}$$

Thus the minimisation of Gibb's free energy approach calculates the most thermodynamically favourable state of a system and therefore models chemical reactions.

An additional heat stream *QDECOMP* connects the decomposer block with the reactor block and carries the Gibb's free energy of formation difference between the biomass feedstock stream *BIOMSS-D* and the decomposed elementary stream *ELEMENTS*. The change of Gibb's free energy of any reaction is the change between the Gibb's free energy of formation of the products and the reactants, as expressed by

$$\Delta G_r = \sum (n\Delta G_f)_{prod} - \sum (n\Delta G_f)_{react} \,. \tag{5-4}$$

By definition, the Gibb's free energy of formation for all elements in their standard state is set to zero, so *QDECOMP* contains the Gibb's free energy of formation of the biomass, which equals the Gibb's free energy of the decomposition reaction and is necessary to maintain an energy balance between the two systems.

Setting up a gasifier with this model and assuming chemical equilibrium approaches was found to be an appropriate approach and to provide realistic chemical properties of the resulting streams, especially for fixed-bed downdraft gasification systems [142, 144, 145].

After gasification reactions have taken place, a separator block *GF-SEPAR* is used to divert ash and unconverted biomass in the form of coal (stream *CHAR*) from the producer gas stream *PRODGAS*. The char and ash stream is treated as a waste stream in this simulation, however the char could also be returned to the gasifier to release its remaining energy. The producer gas stream is the resulting fuel gas stream and is connected to further downstream parts of the plant.

5.2.3 Anaerobic Digester

The anaerobic digester (AD) unit is modelled as a combination of heat exchanger, digester reactor and slurry separator, as shown in Figure 5-4.

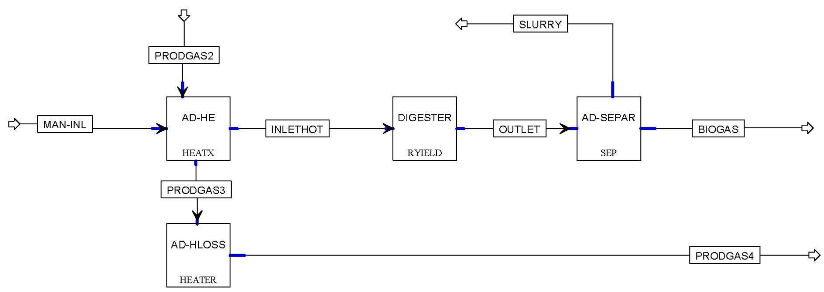

Figure 5-4: Anaerobic Digester Flowsheet Model.

Anaerobic digestion is a very complex process, employing a large number of microbial conversion steps that happen consecutively and/or simultaneously, as has been discussed in section 4.2.2.1 above. Existing anaerobic digestion models in published literature are therefore based on solving a large number of reactions for production of biogas, a mixture of methane and carbon dioxide with traces of water vapour and hydrogen sulphide [146]. This very detailed reaction modelling may be a suitable approach when the main intention of the simulation is to model AD reactions in great detail, however it results in a rather complex model of the plant.

Instead of modelling all occurring reactions, the AD model developed for this project assumes that, based on performance data available in literature, a certain amount of biomass intake is converted into biogas.

Manure in this model is simulated as a mixture of water and nonconventional solids. Following the above discussion on manure moisture and solids contents, a conservative value of 10% has been chosen for the solids content. Products of the AD processes are methane, carbon dioxide and water vapour, which form the biogas stream; and water and solids as effluent, which cover both unconverted solids and microbial cells grown during the process. The biogas stream is set up as containing 5% water vapour, with the remaining volume split into 60% methane and 40% carbon dioxide. These values were chosen on the basis of published data from operational sources [31, 84, 125].

The structure of the AD model follows three main steps: firstly, heat exchangers (*AD-HE* and *AD-HLOSS*) are employed to provide the temperature level necessary to convert manure into biogas. *AD-HE* warms the manure inlet stream *MAN-INL* to a temperature of 35°C while *AD-HLOSS* provides the heat that is lost for retaining the manure at that temperature, as detailed below. The producer gas stream is used as a source for the thermal energy in order to maximise the internal heat usage, as the *PRODGAS2* stream provides sufficient energy to maintain a mesophilic temperature range in the anaerobic digestion reactor and covers heat losses as described below.

The reactor block itself is modelled using an *RYIELD* block (*DIGESTER*), where a certain part of the solids is converted into methane and carbon dioxide. The solids conversion and methane production rates have been chosen in accordance with literature, where values of 100-200m^3 methane per tonne of solids are stated [34, 35, 125, 147].

Finally, a separator block *AD-SEPAR* is used to separate the liquid effluent, which contains water and unconverted biomass solids (stream *SLURRY*), from the *BIOGAS* stream.

The digester has been set up for a manure intake of 11,000kg per day, which results in a tank size of around 220m^3 for an average retention time of 20 days. Out of the total tank volume, $^1/_{20}$ is replaced each day by new manure of ambient temperature, and the remaining volume needs to be maintained at the mesophilic temperature range.

Therefore, the *AD-HLOSS* reactor includes calculations to simulate heat losses from the tank to the surrounding environment.

The total heat taken from the *PRODGAS2* stream consists of the heat losses of the tank to its surroundings (in *AD-HLOSS*) and the heat to warm up new manure from an ambient temperature of 20°C to the mesophilic range of 35°C (in *AD-HE*). It can be described as

$$Q_{AD} = Q_{loss} + Q_{warm} \tag{5-5}$$

with the heat losses to the surroundings being calculated with the formula following from Newton's law of cooling

$$Q_{loss} = U \cdot A \cdot (T_d - T_{amb}) \tag{5-6}$$

and the heat to warm the new manure being

$$Q_{warm} = m \cdot c \cdot (T_d - T_{amb})\,. \tag{5-7}$$

The digester volume V for a cylindrical digester tank can be calculated from the manure intake, its density and the retention time as

$$V = \pi \cdot r^2 \cdot h = m \cdot \rho_{Manure} \cdot HRT\,, \tag{5-8}$$

and by using the formula for the surface area of a typical cylindrical digester shape as

$$A = 2 \cdot \pi \cdot r^2 + 2 \cdot \pi \cdot r \cdot h \tag{5-9}$$

and setting $r = h$ which is a reasonable design for anaerobic digester tanks, the surface area A itself becomes a function of the manure intake m.

The overall heat transfer coefficient U for the reactor depends on the surface material of the reactor and on the ratio of the surface that is exposed to earth or to air. Based on own calculations and available literature [34, 148], U was assigned a conservative value of 1.75W/m^2·K.

In order to maintain a compact simulation, simplifying the occurring reactions during AD in the described way is an acceptable procedure, as results obtained are consistent with published results. The main intention of the model is investigating into local power generation and supply, not modelling microbial reactions in the highest possible level of detail. Biogas production values have been chosen conservatively and the digester model soundly represents the energy demands of a real digester, therefore from a thermodynamic point of view, the reactor design provides all information necessary in order to evaluate whether the reactor can be operated in the intended way.

5.2.4 Microturbine

The microturbine model follows the basic structure of a real microturbine, as discussed in section 4.3.2.1 above; the model, shown in Figure 5-5, consists of the main blocks air compressor, air preheater, combustion chamber and expansion turbine.

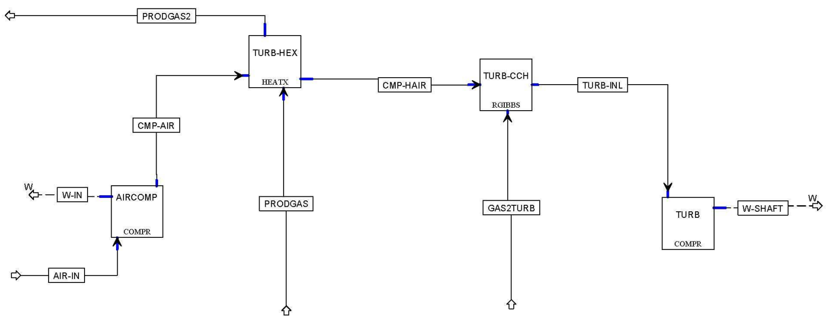

Figure 5-5: Microturbine Flowsheet Model.

An air stream *AIR-IN* is used for combusting the fuel and in the first step is compressed in the *AIRCOMP* block from ambient pressure and temperature to a pressure of 3.35bar. The air mass flow has been chosen to facilitate a minimum lambda of 6, which means that the actual air flow is at least six times the stoichiometrical flow, as expressed by

$$\lambda = \frac{AFR_{act}}{AFR_{stoich}} \geq 6 \tag{5-10}$$

where the stoichiometrically necessary amount is calculated based on the following main combustion reactions that occur in the turbine combustion chamber:

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2 \tag{5-11}$$

$$H_2 + \tfrac{1}{2}O_2 \rightarrow H_2O \tag{5-12}$$

$$CH_4 + 2O_2 \rightarrow CO_2 + H_2O \tag{5-13}$$

The combustion chamber outlet stream temperature is limited due to material constraints of the microturbine blades. The turbine blades can be exposed to a maximum temperature of 1000°C [108], therefore a design specification restricts the combustion chamber to meet this value by means of regulating the amount of air intake.

Similarly, literature values have been used to model the air compressor, whose overall efficiency can be expressed through its isentropic and mechanical efficiency [149]. The isentropic compression efficiency η_{is} compares the actual power of the compression process ($\dot{W}_{act}$) with the theoretical isentropic power ($\dot{W}_{is}$) and is defined as

$$\eta_{is} = \frac{\dot{W}_{is}}{\dot{W}_{act}} = \frac{h_{2s} - h_1}{h_2 - h_1} \tag{5-14}$$

with h_1 being the enthalpy of the uncompressed stream, h_2 being the actual (or real) enthalpy of the compressed stream and h_{2s} being the isentropic (or theoretical) enthalpy of the compressed stream. Typical isentropic efficiencies were mentioned as 70-92%, depending on the compressor type and compression ratio, and a value of 74% was chosen in accordance with literature [149].

The mechanical efficiency η_{mech} compares the mechanical shaft power needed by the compressor ($\dot{W}_{in}$) with the actual power needed for the compression process ($\dot{W}_{act}$); it thus includes mechanical losses such as bearing friction and is defined as

$$\eta_{mech} = \frac{\dot{W}_{act}}{\dot{W}_{in}} \tag{5-15}$$

A value of 89% for the mechanical efficiency of the compressor was chosen following literature recommendations [149].

A work stream *W-IN* was thus connected to the *AIRCOMP* block to simulate the mechanical shaft power needed by the compressor, in order to calculate the net available turbine work as

$$W_{net,turb} = W_{shaft} - W_{in} \tag{5-16}$$

The compressed air stream is then directed into a heat exchanger where it is heated by the hot producer gas stream. The amount of heat exchanged between the hot and cold gas streams can be calculated using the following equation:

$$Q_{exch} = UA_{surface}\Delta T_{LM} \tag{5-17}$$

with U being the overall heat transfer coefficient of the heat exchanger, $A_{surface}$ being the surface area of the heat exchanger pipes, and ΔT_{LM} being the logarithmic mean temperature difference, which can be calculated as

$$\Delta T_{LM} = \frac{\Delta t_0 - \Delta t_L}{\ln \frac{\Delta t_0}{\Delta t_L}} \tag{5-18}$$

with Δt_0 being the highest and Δt_L being the lowest temperature difference between the hot and cold gas streams in the exchanger [150]. Values for the geometry of the exchanger as well as for the overall heat transfer coefficients were chosen according to literature [150-152].

After being preheated, the hot air stream *CMP-HAIR* enters the combustion chamber where the combustion reactions take place. The *TURB-CCH* block has been modelled as an *RGIBBS* reactor using the approach described above; alternative simulations with an *RYIELD* reactor using combustion reactions have shown very similar results, therefore both reactor types can be used for the simulation. Since the Gibb's free energy approach also considers minor exhaust gases such as NO_X and SO_2, it was preferred over the *RYIELD* reactor.

The fuel gas stream *GAS2TURB* originates from the gas storage and consists of compressed producer gas and biogas. A pressure level of 5bar is applied to satisfy minimum energy input requirements. This fuel gas is burnt and the hot and high pressure exhaust stream *TURB-INL* is entering the turbine block *TURB* where it is expanded to atmospheric discharge pressure. The turbine inlet temperature and pressure as well as turbine performance parameters have been chosen in accordance to microturbine specifications as mentioned in literature [113, 119, 149].

A resulting work stream *W-SHAFT* carries the expansion work of the exhaust gases on the turbine blades, and an atmospheric exhaust gas stream *EXHAUST* exits the microturbine section and is used in the wood dryer unit, as it still contains considerable amounts of thermal energy.

5.2.5 Gas Storage System

The gas storage system acts as the fuel and thus capacity storage within the plant and is shown in Figure 5-6. It is intended to render unnecessary electric storage such as batteries that are normally employed in grid independent plant designs, and plays another crucial role in levelling out supply and demand through the variable power fuel gas compressor.

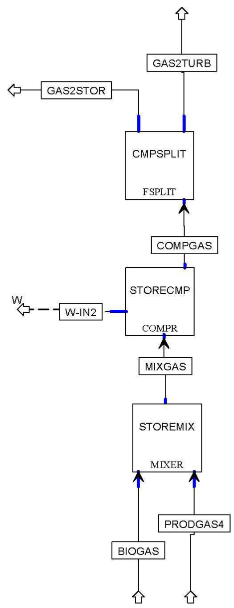

Figure 5-6: Gas Storage System Flowsheet Model.

The system consists of a mixer that combines the producer gas and biogas streams and stores this uncompressed gas, followed by a gas compressor and a compressed storage. The compressed storage is modelled through a splitter *CMPSPLIT* with an exit stream *GAS2STOR* that can be used to reroute part of the gas mixture to a storage, and the remaining compressed fuel gas stream *GAS2TURB* that is sent to and burnt in the turbine combustion chamber.

The producer gas stream arriving at the gas storage system comprises of a relatively cold gas stream, as it has been used in the turbine and AD heat exchangers earlier on. In block *STOREMIX*, it is mixed with the biogas stream that exits from the digester system. Afterwards, part of the stream can be diverted to form an uncompressed storage, and the remaining stream is compressed in block *STORECMP* to a pressure level of 5bar. This level satisfies the microturbine minimum energy inflow [123] and also minimises the storage volume of the compressed gas. The compressor performance parameters are modelled based on literature values [149], and similarly, the compressor power input is modelled by means of a work stream *W-IN2*.

This means that the overall system net work output can be calculated as

$$W_{net,tot} = W_{net,turb} - W_{in\_2} \tag{5-19}$$

This power output can then be adjusted in order to match the actual power demand in operational load simulations. By adjusting the turbine power level, the share of compressed fuel gas to be directed to the storage can be calculated. The storage fuel ratio, which is expressed by

$$\sigma = \frac{m_{GAS2STOR}}{m_{GAS2TURB}} \tag{5-20}$$

can then be varied, which results in the combustion air flow through the turbine being changed accordingly, as it is connected via the lambda value. This variable air and fuel intake has been described in section 4.3.2.1 above as the variable-speed/constant-temperature mode for regulating the microturbine power output, and it is the most efficient way of operating a microturbine under variable load [129].

5.2.6 Wood Dryer and Electric Heater

The wood drying facilities are the last remaining plant subsystem and are used to intensify internal heat usage. By using as much thermal energy as possible to dry the feedstock, the amount and quality of the producer gas and thus the efficiency of the whole generation system will be enhanced. A producer gas with a higher calorific value will be the result, and this gas can then be stored as a capacity for generation, as will be described in detail in the load simulation studies in section 7.2.

Both the wood dryer and the electric heater are simulated by means of two consecutive blocks, as shown in Figure 5-7 and Figure 5-8.

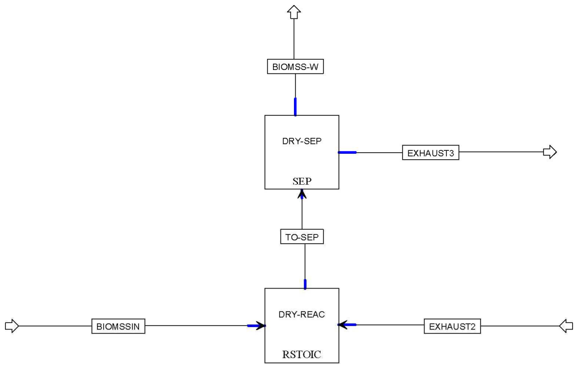

Figure 5-7: Wood Dryer Flowsheet Model.

The wet biomass stream *BIOMSSIN* first enters the wood dryer, which uses the heat of the microturbine exhaust stream *EXHAUST2*. This stream contains minor amounts of NO_X, SO_2 and other combustion residues, so in order to prevent feedstock contamination, a conductive or indirect dryer design needs to be adopted. This means that the feedstock will not be in direct contact with the exhaust gas stream, but instead a heated surface between the biomass and the exhaust gases will act as the evaporation heat carrier. Conductive dryers have a higher thermal efficiency than their convective or direct heat counterparts and are more suitable for products with higher moisture contents, such as wet biomass [153].

Initially, a moisture content of 60% has been implemented for the biomass intake stream *BIOMSSIN*. As discussed in section 4.1.1 above, fresh wood biomass contains between 30-60% moisture, so in order to obtain robust simulation results this conservatively high value has been chosen. Again, biomass itself is modelled as a nonconventional material stream based on its proximate and ultimate analysis, as described above.

The first reactor block, *DRY-REAC*, calculates the amount of water that needs to be evaporated to reach a pre-set exit moisture content for the biomass of 10%, which was mentioned as a target value for stable operation of the gasifier [27]. The heat energy necessary for evaporation of this amount of water is then calculated on the basis of literature values for conductive dryer applications [145, 153], and the energy balance between the biomass intake stream and the exhaust gas stream is established.

Both streams are then directed into the separator block *DRY-SEP* where the dried biomass stream is diverted from the vapour stream. The latter consists of the evaporated water from the biomass and the exhaust stream gases. The dried biomass stream *BIOMSS-W* is connected to the electric heater, whereas the exhaust stream *EXHAUST3* is modelled as being stacked. However, it could also be used for additional external heat transfer applications since it still contains considerable amounts of thermal energy.

The electric heater forms the second feedstock drying unit and is the main power sink implemented in the plant model. The plant has to ensure a balance between demand and generation at each unit of time in order to facilitate security of supply. Due to no electricity storage being implemented in this design, the microturbine needs to always generate at least the amount of power requested by the customers. However, generation will always have to exceed the demand, since real time mirroring of the power demand is impossible, as discussed above. Therefore, a certain amount of power needs to be "used up" to achieve a match between generation and demand. The electric heater forms the power sink to "use up" this excess power by converting it into useful heat to further dry the feedstock. Its flowsheet is shown in Figure 5-8.

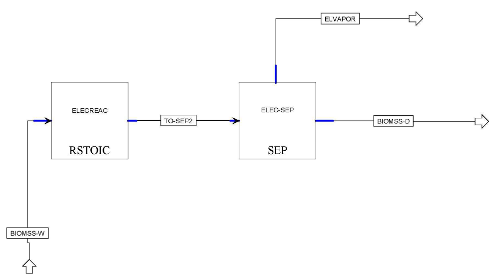

Figure 5-8: Electric Heater Flowsheet Model.

The electric heater comprises of the two reactor blocks *ELECREAC* and *ELEC-SEP*. In the first block, the amount of water that can be evaporated from the pre-dried biomass stream *BIOMSS-W* is calculated on the basis of the available sink power W_{avail}. This power is the difference between generation (including the variable compressor power level, see eqn. 5-19) and demand, and can be calculated as

$$W_{avail} = W_{net,tot} - W_{demand} \tag{5-21}$$

Since both power demand and power generation will fluctuate continuously as will be shown in the simulation chapters below, the resulting available sink power will also be highly variable and volatile. However, since the electric heater simply converts electric power into heat, it has virtually no requirements with regards to power quality or reliability, and it can be operated without problems on highly fluctuating power levels and even on disharmonics and power spikes [5].

On the basis of the available sink power, the amount of water to be vaporised can then be calculated by employing the moisture vaporisation heat value for biomass wood chips. This value provides the necessary energy input to evaporate water from biomass wood chips, and literature mentions values from 1.5-3 times the vaporisation heat of water (2.3MJ/kg), depending on the properties of the wood chips and the drying technology [153, 154]. For this project, a conservative value of 5MJ per kg of water to be evaporated was chosen.

For the plant feasibility study, the available sink power was initially set to a constant value of 5kW. The *ELECREAC* block then adjusts the biomass moisture content accordingly, and finally the block *ELEC-SEP* separates the exhaust water vapour stream *ELVAPOR* from the dried biomass stream *BIOMSS-D*, which is then directed to the gasifier.

After running through both the wood dryer and the electric heater, the dried biomass stream moisture content will always be 10% or less, as follows from

$$mc_{BIOMSS-D}\begin{cases} =10\% & for \quad W_{avail}=0 \\ <10\% & for \quad W_{avail}>0 \end{cases}. \tag{5-22}$$

The simulation model of the wood dryer and the electric heater concludes the whole plant design and thus the model set up in Aspen Plus, and in the following chapter it will be evaluated whether this chosen design is feasible and whether any limitations of size exist for this model.

6 Feasibility and Size Limitation Analysis

On the basis of the plant description and the simulation model presented in chapter 5, this chapter undertakes feasibility and size limitation analyses. In the first part, the model will be evaluated to prove whether and under what circumstances the plant design is feasible and can be operated. Those cases found to provide feasible and suitable results are then used as base cases.

In the second part of this chapter, feasible size ranges of the plant design are investigated on the basis of the previously defined base cases. Since the plant is intended for a remote group of customers, it will have to provide the amount of power requested by the customers. This however means that a whole power range could be suitable for this plant, depending on the amount of customers and on their power demand characteristics. Whilst domestic load patterns and load profiles will be analysed in chapter 7, this chapter will analyse what power range can be provided with this design.

A feedstock availability analysis to evaluate which combination of the two feedstock sources will have to be provided for a certain power range will then conclude this chapter.

6.1 Feasibility Analysis and Results

In order to check and prove the feasibility of the plant design, each sub-unit was individually tested after modelling, and its results were compared to literature values of operational units. After assembling the sub-units into a combined plant system and connecting all streams within the plant, the whole system model was analysed. As a first step, a heat energy optimisation analysis was undertaken to develop suitable scales of the individual units in relation to each other. As the plant utilises heat streams internally, the two conversion systems' heat inputs and outputs were analysed in order to find feasible combinations. The ratio between wood and manure intake found to provide best results is shown in Table 6-I for a set of chosen cases. It can be seen that a ratio of 1:10 was chosen for all cases but the smallest, whose slightly different ratio was caused by exponential digester heat losses, which will be discussed in detail in the size limitation section below. The minimum case of the plant was defined as the base case and is named *B1*. The raw feedstock inputs were then varied in order to check which scaling of the plant design provides suitable results, and the minimum plant size B1 was scaled to around three times the wood and manure intake, a range within which all sizes provided feasible results.

Table 6-I: Base Case Scaling.

Case Name	Wood [kg/hr]	Manure [tonne/day]
B1 (base)	112.5	11
B2	150	15
B3	200	20
B4	250	25
B5	300	30

The net overall available power and the net turbine output power resulting from these cases are given in Table 6-II, in addition the ratio of turbine power to overall power is given as the output efficiency.

Table 6-II: Scaling Power Output.

Case Name	$W_{net,tot}$ [kW]	$W_{net,turb}$ [kW]	$\eta_{turb \rightarrow tot}$ [%]
B1 (base)	60.418	72.551	83.3
B2	80.541	97.320	82.8
B3	106.732	130.085	82.0
B4	132.449	162.952	81.3
B5	157.924	195.947	80.6

It can be seen that for the range of common microturbine output power, which is up to around 200kW, an available power level of 60-160kW can be provided. This level is also a suitable size for smaller villages or industrial customers, as will be discussed in chapter 7.1 below. The efficiencies shown in Table 6-II indicate that more than four fifths of the turbine output can be used as electricity for the customer, with the rest being needed by the fuel compressor. Values of up to 20% of output power being needed for the fuel compressor have been mentioned elsewhere [47], so the values provided above are realistic.

In terms of plant size, the chosen base cases result in a digester tank size of between 200m^3 and 600m^3, and given that all other equipment is rather compact, the plant could easily be set up in the vicinity of areas of demand.

6.1.1 Gasifier Results

The gasifier is fed with the respective amount of biomass from the dryers and preheated air is used as the gasification medium. The air stream enters the gasifier heat exchanger and is heated to around 650°C, which provides sufficient heat to produce a high quality producer gas. As the turbine exhaust gas stream is used as the heat source for the gasifier heat exchanger, this energy can be supplied continuously.

The hot gasification air and the pre-dried biomass particles then enter the gasifier and are converted into producer gas. The volume-based producer gas composition for the base case is shown in Table 6-III and varies less than 2% for the different cases. The other minor components included are CH_4, C_2H_6, NO, N_2O, SO_2, H_2S and NH_3. Due to the amount of moisture in the biomass, the producer gas contains around 2-4% of water vapour when it leaves the reactor with around 710-730°C.

Table 6-III: Producer Gas Composition [vol%, dry base].

N_2	CO	CO_2	H_2	Other
38.0	32.7	5.7	23.6	0.01

These results are comparable to results of similarly scaled and designed gasifiers published in literature [27, 33, 60, 61]. N_2 and CO_2 values tend to be higher and CO values lower than those mentioned in Table 6-III; this ratio however strongly depends on the gasifier air/fuel ratio which differs between the different literature sources. Additionally, the gasification air temperature of 650°C is higher than in most applications, which also favours higher quality producer gas.

Table 6-IV shows the mass fractions, gas densities and lower heating values for the producer gas components [6], and by using the formula

$$LHV = \sum_i \left(\frac{mf_i}{\rho_i} \cdot LHV_i\right) \qquad (6\text{-}1)$$

a total lower heating value of around 6.1MJ/Nm^3 can be calculated for the producer gas mix. This value is on the upper level of reported values, however this again can be related to a different air/fuel ratio, a higher gasification air temperature and the fact that the wood moisture content is set to a maximum of only 10%. In general, temperature levels applied in literature tend to be lower than in this design. This is mainly caused by the need to provide fuel for preheating the air, whilst in this design a high calorific producer gas can be created without the need for additional fuel by using the microturbine exhaust heat.

Table 6-IV: Producer Gas Component Properties.

Component i	Mass Fraction mf [%]	Density ρ [kg/m^3]	Lw Heating Value LHV [kJ/Nm^3]
N_2	45.622	1.1646	–
CO	39.286	1.1643	11,770
CO_2	10.778	1.8296	–
H_2O	2.260	1.0000	–
H_2	2.046	0.0838	10,060
NH_3	0.004	0.7080	13,150
H_2S	0.003	1.4168	21,540
C_2H_6	< 0.001	1.2501	59,370

The gas stream is then used in the microturbine heat exchanger to preheat the compressed air, where a temperature drop of around 350°C occurs. This shows that the producer gas stream contains sufficient energy to use it for preheating the compressed air. Afterwards, it is used as the hot stream medium for the AD heat exchangers which results in a lowering of its temperature down to less than 100°C. This result is also realistic as the manure stream is heated from ambient temperature to around 35°C and the two media are in contact with each other. Besides enhancing the overall process efficiency by internally using the producer gas heat, lowering its temperature as much as possible also reduces the gas storage compressor power, as it needs significantly less power to compress a low-temperature gas stream than a hot stream.

6.1.2 Anaerobic Digester Results

The anaerobic digester is set up with a manure intake at ambient temperature of 20°C. The heat duty calculation for this system reveals that for the cases chosen, the heat losses for keeping the manure at mesophilic temperatures are between 70-100% of the heat duty to warm up the new intake, as shown in Table 6-V.

Table 6-V: Anaerobic Digester Heat Calculation.

Case Name	Q_{warm} [kW]	Q_{loss} [kW]	Q_{loss}/Q_{warm} [%]
B1 (base)	7.456	7.472	100.2
B2	10.160	9.190	90.5
B3	13.550	11.130	82.1
B4	16.950	12.910	76.2
B5	20.340	14.580	71.7

The biogas stream composition for each of the cases is shown in Table 6-VI and results from the CH_4/CO_2 split that the model calculates, and from the fact that the gas is saturated with water vapour when it leaves the digester. Using eqn. 6-1 and the densities and heating values as shown in Table 6-IV above, a lower heating value of around 18.8MJ/Nm^3 can be calculated for the biogas.

Table 6-VI: Biogas Composition.

Case Name	CH_4 [kg/hr]	CO_2 [kg/hr]	H_2O [kg/hr]
B1 (base)	4.44	8.17	0.66
B2	6.05	11.14	0.90
B3	8.07	14.85	1.21
B4	10.08	18.56	1.51
B5	12.10	22.28	1.81

Due to both streams being mixed afterwards, the biogas heating value significantly increases the heating value of the gas mixture and thereby minimises the gas compressor power input, which is necessary to maintain a minimum energy intake flow for the microturbine, as will be discussed in the following section.

6.1.3 Gas Storage System and Fuel Compressor Results

The compressor power necessary for the different cases has been mentioned in Table 6-II before. Since it is strongly related to the temperature of the producer gas stream, an efficient internal heat usage not only results in better process efficiency, but also in a low producer gas temperature and thus less power input for the compressor.

In the base case, the whole producer gas/biogas mixture from the conversion reactors is immediately compressed by the fuel compressor and burnt by the turbine. To investigate the plant flexibility and operation, the storage ratio has been varied for the base case scenario. To meet local demand, the plant will need to be operated on levels below nominal full power, as demand varies throughout the day. The load demand analysis will be undertaken in chapter 7, however several microturbine load steps were analysed in this study to evaluate part load operation feasibility. The microturbine efficiency strongly decreases for power outputs less than 50% of the nominal turbine power [129], thus it was decided that the turbine should always operate on at least half its nominal power in order to provide operation stability and maintain efficiency. Therefore, storage factors in the range of $0 \le \sigma \le 1$ were investigated, which means that between none and half of the producer gas/biogas mixture is not burnt in the turbine, but sent to storage. The impacts of this variation on the turbine output power and the total available power is shown in Table 6-VII.

Table 6-VII: Power Output for Storage Ratio Variations.

σ	$W_{net,tot}$ [kW]	$W_{net,turb}$ [kW]	$\eta_{turb \rightarrow tot}$ [%]
0 (base)	60.418	72.551	83.3
0.11	53.428	65.677	81.3
0.25	46.407	58.794	78.9
0.43	39.367	51.919	75.8
0.67	32.243	44.999	71.7
1	25.040	38.055	65.8

As expected, with a rising sigma, the total turbine output power as well as the available power decrease linearly from 70kW to around 40kW. As the power for the fuel compressor stays nearly constant, the total efficiency decreases.

The influence of varying the storage ratio on the temperature of some key streams of the plant is shown in Figure 6-1.

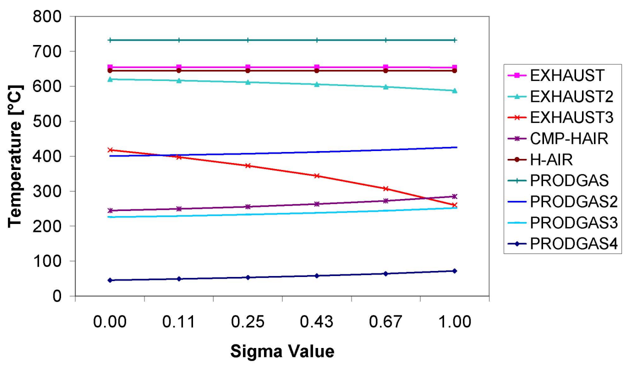

Figure 6-1: Plant Stream Temperature Profiles.

It can be seen that although the nominal power output of the turbine decreases, the *EXHAUST* stream temperature stays constant. This is related to the temperature of the compressed turbine air stream *CMP-HAIR*, which rises from 240°C for σ=0 to 280°C for σ=1. As less fuel gas is burnt in the turbine combustion chamber, less air mass flow is necessary for combustion. This air flow is however preheated by the producer gas stream (*PRODGAS*), and as nearly the same amount of heat is transferred in the turbine heat exchanger, this results in a higher temperature of the compressed air stream.

Although the exhaust gas mass stream decreases due to less fuel being burnt, it still contains enough energy to preheat the gasification air. Since the *H-AIR* stream temperature is being pegged to the *EXHAUST* temperature level, the result is that this lower exhaust gas mass flow needs to provide the same amount of heat for the gasification air, which results in the *EXHAUST2* stream temperature decreasing from around 620°C for σ=0 to around 580°C for σ=1.

It is also shown in Figure 6-1 that the *EXHAUST2* stream still contains enough energy to maintain the maximum moisture content in the wood dryer of 10%. As the same amount of heat is necessary due to a constant wood intake, the *EXHAUST3* stream temperature decreases from 420°C to 260°C over the variation of σ due to its decreasing mass flow. However, the dryer can continuously produce biomass with a moisture content of 10% over the whole range.

The *PRODGAS* temperature stays nearly constant over the whole range, which is due to the gasification air stream *H-AIR* temperature being pegged to the constant *EXHAUST* stream temperature. The fact that the *PRODGAS2*, *PRODGAS3* and *PRODGAS4* temperatures slightly raise is again related to the turbine heat exchanger and the decrease in the compressed air stream mass flow.

After passing the two AD heat exchangers, the producer gas stream *PRODGAS4* reaches a temperature level close to the digester temperature. Since this temperature rises with increasing storage ratio, a value of σ=1 should not be exceeded as it increases the amount of power necessary for the fuel compressor. This however fits with the turbine not being operated on less than 50% of the nominal power.

6.1.4 Wood Dryer and Electric Heater Results

The electric heater acts as the power sink for that part of generated power that is not needed by demand. As described, in the base case it is set to a flat power intake of 5kW. Since the wood dryer always provides enough exhaust heat to dry the wood chips from a moisture content of 60% to 10%, the electric heater power intake is limited to the amount of energy necessary to evaporate the remaining water; otherwise it would not just dry but start to decompose the wood chips.

The *BIOMSS-W* stream consists of a 50kg/hr flow of biomass with a moisture content of 10%, so a maximum of 5kg/hr of water is available for evaporation in the electric heater. However, the feedstock cannot realistically be dried to 0%, so a maximum of 90% of this moisture has been assumed to be available for evaporation.

For the base case and the amount of energy necessary to evaporate water from wood mentioned before, a continuous power intake of W_{avail}=6.25kW results in maximum water evaporation. This translates into a fraction of around 10% of the total available power output when the turbine is running on full load, or 25% when the turbine is running on half load, which has been defined as the minimum power output. As this can be treated as the power sink capacity, it needs to be evaluated whether this capacity is sufficient. However, to assume a flat power intake of 6.25kW for the electric heater over long time intervals, e.g. of one hour, is not realistic. The electric heater will have to compensate excess power in case of a demand slump, but only for as long as the microturbine output power will be adjusted in order to meet the new lower load. This means that it might have to compensate more than 6.25kW, however only for a couple of minutes or less.

The amount of continuous power input for drying in the heater for a long period, e.g. one hour, can be calculated as the sum of time-weighted incremental power inputs by

$$W_{avail} = \frac{\sum P_i \Delta t_i}{3600s} \text{ in } [W = \frac{J}{s}] \tag{6-2}$$

where P_i stands for the incremental amount of power input in Watts that is necessary for a period of time defined by Δt_i in seconds. The computed flat power intake of 6.25kW=6.25kWh/h is thus the maximum value that W_{avail} can accommodate, which however means that significantly higher short-term power intakes P_i can be accommodated by the electric heater as long as the total power intake is below the 6.25kW threshold within the longer total period.

6.2 Size Limitation Analysis

After having obtained a feasible minimum size base case B1 and having proven that upscaling of the plant design can be achieved easily, this section will analyse the technological size limitations of the design. To understand the impact of downscaling the plant processes further, energy analyses of each of the main sub-systems of the plant were undertaken. This means that the two conversion systems (gasification and anaerobic digestion) and the generation unit (microturbine) were investigated. Afterwards, each unit's energy supply and demand balance was calculated and combined to a total system energy balance. This then provides a range of feasible sizes for the sub-units which results in an optimised overall plant system.

Finally, a feedstock sourcing analysis was undertaken to reveal what power output is achievable with a given amount of feedstock, and what limitations exist for the requirement of ongoing and sustainable feedstock provision.

6.2.1 Anaerobic Digester Size Analysis

The anaerobic digester (AD) unit mainly consists of a tank in which bacteria digest wet feedstock such as manure, sludge or vegetable waste, and produce a gas mixture of CH_4 and CO_2. The feedstock intake is kept at a reactor temperature of 35°C and is held for a period of 20 days. In intervals, new feedstock replaces part of the tank volume, which means that this new feedstock needs to be heated to the reactor temperature.

The AD size limitation mainly depends on its energy balance, as the digester should provide more energy than it consumes in order to be a net energy providing conversion technology. Whilst AD technology itself has been known and employed for decades [81-83], energy analysis of such a system is a more recent development, as in history the main intention of the digester was hygienic treatment of manure. Using it as an energy source has only recently gained interest and resulted in a more detailed discussion of its energy streams [81, 83].

The main energy output of an AD depends on the amount and consistency of the biogas stream produced, given that the heat of the biogas stream will not be useable. As discussed in the modelling section above, its energy demands can be classified as [34, 81, 155]

I. the electricity or heat for heating the inflow manure to the digester temperature
II. the electricity or heat for maintaining the digester temperature, i.e. for compensation of digester heat losses
III. the electricity for mixing the tank and
IV. the electricity for pumping and for other auxiliary services.

For the digester system employed in this plant design, an energy analysis considering these main energy inputs was undertaken.

The heating energy Q_{heat} normally forms one of the two main energy demands of an AD system [81, 155]. Following eqn. 5-7, it can be calculated as

$$Q_{heat} = m_1 \cdot c \cdot (T_d - T_{amb}) . \tag{6-3}$$

It thus depends on the temperature difference between ambient feedstock inflow temperature and digester temperature, and on the heat capacity of the manure. As these two factors remain constant during operation, Q_{heat} thus becomes a function of the wet feedstock intake m_1.

The energy demand to compensate for the digester heat losses to its surroundings Q_{loss} forms the second main energy demand of an AD system [81, 155]. Despite the tanks being insulated, a heat transfer between the digester walls and the surrounding environment occurs because the temperature within the reactor is normally above the ambient temperature. Following eqn. 5-6, Q_{loss} can be calculated as

$$Q_{loss} = U \cdot A \cdot (T_d - T_{amb}) . \tag{6-4}$$

This energy demand thus also depends on the temperature difference between reactor and surroundings, as well as on the digester surface area and on the overall heat transfer coefficient, a constant related to the insulation of the digester.

The digester surface area itself however is a function of the daily feedstock intake. Feedstock is kept in the tank for 20 days, and each day a certain amount is replaced with new intake. Thus, the daily intake volume determines the digester tank volume and hence its surface area. Therefore, for a given digester geometry the digester surface area A can be formulated as a function of the daily feedstock intake of the digester system, and hence the energy demand itself becomes a function of the manure intake m_1. This means that the energy demand of those two main input streams can be formulated as

$$Q_{main} = F(m_1) = Q_{heat} + Q_{loss} . \tag{6-5}$$

These energy requirements can be provided by both heat or electricity, as heat is the energy carrier needed. The mixing and pumping energy demands however have to be provided in the form of electricity. It has been calculated that for common AD systems, these demands are small when compared to the above two main energy streams, and hence they can be included in the calculation in the form of percentages [34, 81, 155]. For the AD size limitation studies in this project, values have been used in accordance with literature, and the total energy demand for pumping, mixing and auxiliary services was chosen as 10% of the heating and heat loss energy, which means that the total system heat demand can be calculated as

$$Q_{AD} = 1.1 \cdot Q_{main} . \tag{6-6}$$

The energy demand of the digester and its three main components are shown in Figure 6-2 as a function of the raw manure intake m_1. It can be seen that for small scales, the heat losses (Q_{loss}) are higher than the heat demand of the digester (Q_{heat}), whilst for larger scales the heat demand is the main component of the overall energy demand.

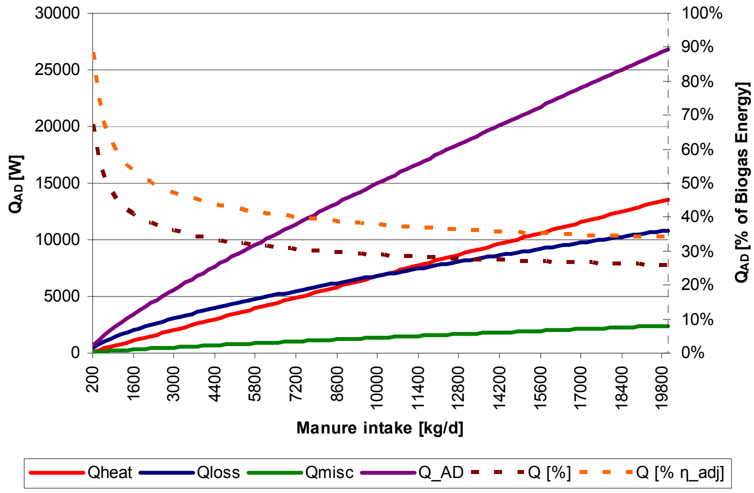

Figure 6-2: Anaerobic Digester Energy Demand and Energy Balance.

The dashed lines show the total energy demand as a percentage of the energy contained in the produced biogas. It however has to be considered that the energy demand of the digester cannot be provided without energy transfer losses. Hence, the adjusted energy demand of the digester as a percentage of the biogas energy was also calculated including conversion efficiencies, and those higher percentages are also shown in Figure 6-2. The energy demand of the digester includes electricity and heat, thus the efficiencies of converting the biogas chemical energy into heat (90%) and electricity (30%) [156] were applied.

It can be seen that for small digesters with less than one tonne per day of manure intake, the total energy demand can be close to the energy of the biogas, which results in a net zero or even negative energy balance for those small digester systems and implies that the system fails to be a feasible energy provider. This means that a chosen size for this AD system should be above one tonne per day of feedstock. The chosen base case size of 11 tonnes per day of slurry results in the total energy demand being between 30-40% of the digester output, which is acceptable and comparable to other operational plants [34, 81, 155].

6.2.2 Gasifier Size Analysis

Gasification as the substochiometric combustion or part-oxidation of feedstock into a producer gas is an exothermic process, which means that the energy of combustion is received from the feedstock [52]. Theoretically, this process can hence be minimised indefinitely, as it itself is not subject to size limitations.

However, a certain amount of heat is necessary to maintain ongoing feedstock conversion. The air that is used as the gasification agent needs to be provided in a temperature range of around 700-800°C in order to facilitate the drying, pyrolysis and oxidation zones within the gasifier [29, 44]. This can be achieved by either utilising the process heat of the producer gas or by supplying this energy by combusting part of the feedstock. Alternatively, this energy can be provided by other high temperature heat streams.

In either case, the amount of energy necessary for preheating is a function of the mass flow of air to be preheated. The ratio between feedstock intake and gasification air however is constant, as an air/fuel ratio of 1.5 based on dry ash-free biomass was chosen for the model. Therefore, the heat exchanger energy demand Q_{GasHEX} only depends on the wood intake m_2.

Heat losses from the gasifier to its surroundings occur, however with <1% they are negligible, as throughput times are small and in the order of several minutes [52].

The gasifier can however only process feedstock with a certain water content. As mentioned earlier, during the gasification process all water will be vaporised, so high water contents would reduce the process efficiency and result in related issues such as fouling. Drying the raw wet wood chips, which can contain up to 60% moisture, to a level suitable for gasification (around 10%) requires significant energy. This drying can be facilitated by a wood dryer that uses either electricity or thermal energy to vaporise the excess water.

The energy demand of the dryer Q_{Dryer} will depend on the amount of water to be evaporated from the raw wood chips. As discussed earlier, the energy necessary to evaporate water from various biomass feedstocks can be assumed as a constant, which depends on the size and type of feedstock. The amount of water to be evaporated however is a function of the wet feedstock intake m_2, thus the overall energy demand of the dryer also becomes a function of the wood intake. Therefore, the total gasifier heat demand can be formulated as

$$Q_{Gasifier} = F(m_2) = Q_{GasHEX} + Q_{Dryer} \tag{6-7}$$

Based on these values, the energy demand for the gasifier is shown in Figure 6-3 as a function of the wood intake m_2. Both the heat demand to preheat the gasification air Q_{GasHEX} and the dryer heat demand Q_{Dryer} are shown. It can be seen that Q_{Dryer} is significantly larger than Q_{GasHEX}. The initial moisture content of 60% is lowered to 10%, so there is a significant amount of water to be evaporated from the feedstock.

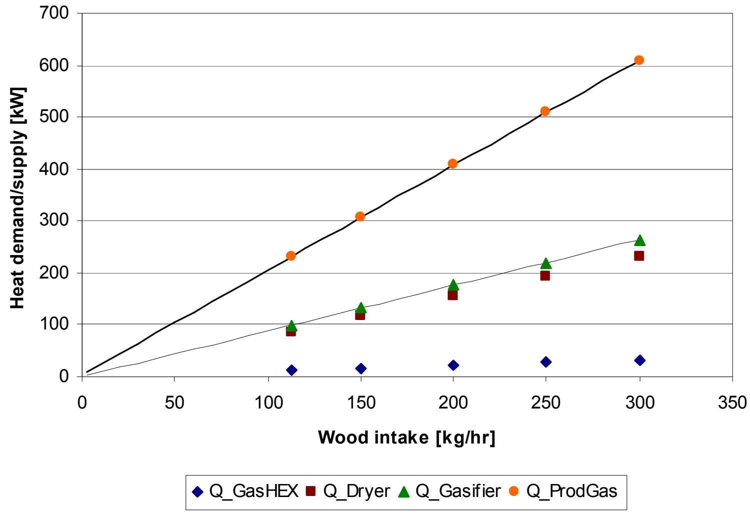

Figure 6-3: Gasifier Energy Demand and Energy Balance.

The energy balance of the gasifier can be analysed by considering the thermal and chemical energy of the producer gas stream. As the gas stream leaves the gasifier at a temperature of around 700°C, the thermal energy stored in the gas is considerable. Together with the chemical energy of the fuel components hydrogen and carbon monoxide, the energy stored in the producer gas is shown as the line named $Q_{ProdGas}$.

For the energy demand and supply balance of the system, the trend lines are shown in Figure 6-3 and it can be seen that the energy demand is always below the amount of energy contained in the producer gas. The linear trend lines were verified by adjusting the simulation model to lower wood intake amounts. As expected, the exothermic gasification process thus does not have an energy size limitation and could (in theory) be minimized indefinitely, as long as the reactor technology can be designed for the respective size.

6.2.3 Microturbine Size Analysis

The energy requirements or inputs of the microturbine are dictated by the work required to compress the combustion air prior to it entering the combustion chamber, and the energy to preheat the compressed air before it gets in contact with the fuel gas.

Whilst the work demand is automatically provided by part of the microturbine expansion shaft work as both the turbine and the compressor are mounted on the same shaft, the energy to preheat the combustion air can be provided by either the turbine effluent using a recuperator, or by another heat stream within the system [116].

Therefore, the microturbine does not have any inherent size limitations on the basis of its energy analysis. However, as described in section 4.3.2.1 above, available microturbine technology is limited to sizes of 25kW upwards, which results from a lower conversion efficiency with lower sizes, so this could be seen as a natural size limitation; however, even smaller turbines down to 1-5kW were reported in literature [121], although they have never actually been marketed.

6.2.4 Combined System Size Analysis

Having analysed the energy balances of the two conversion systems and having evaluated feasible ranges of scale, these can now be used for a combined plant. One objective of the plant design was to use internal heat within the system as efficiently as possible in order to increase efficiency, so it was decided to use the producer gas as the heat source of the digester, and the microturbine exhaust stream as the heat source of the wood dryer and gasification heat exchanger. This however only has a slight impact on the energy balance of the whole system when compared to the unit energy balances, as will be shown in this section.

In a two-variable approach, size ranges of the AD and the gasification system were combined to evaluate the overall energy balance and to understand which size combinations are feasible. The analysed range of size combinations is shown in the area chart in Figure 6-4, and the traffic-light system was used to classify the energy balance results. For a given pair of biomass feedstock intake (manure intake m_1 |

wood intake m_2), Figure 6-4 shows whether the system energy balance is in equilibrium (green area), positive (orange area) or negative (red area).

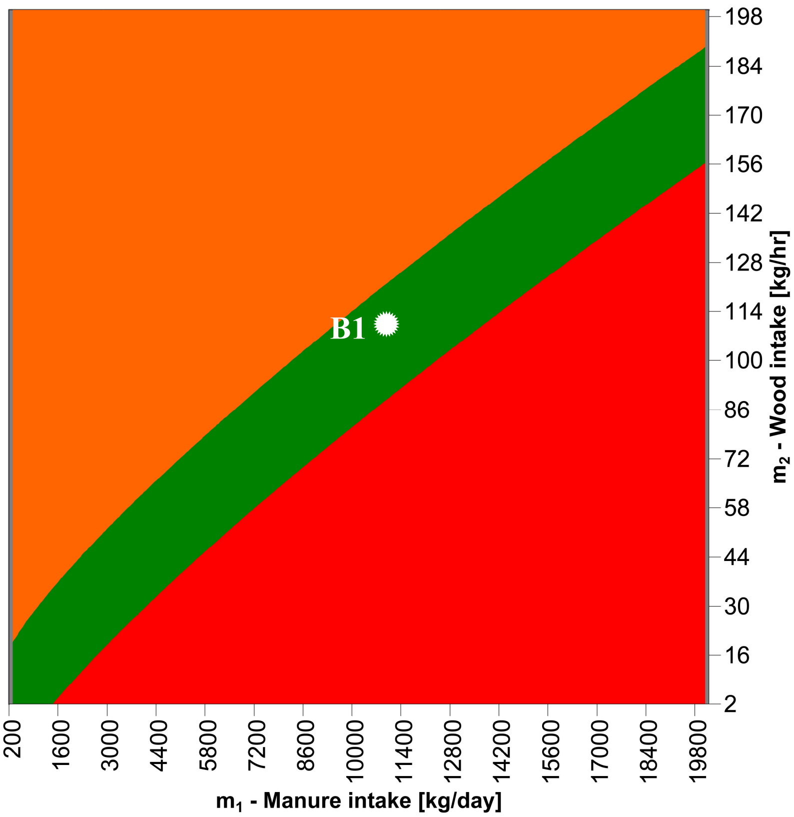

Figure 6-4: System Energy Balance for Pairs of Manure and Wood Intake.

An energy balance in equilibrium means that the energy demand equals its supply, hence the system energy demand can be provided by its own energy supply, which means that the system is feasible. For the energy balance becoming positive, it means that less energy is demanded than could be supplied, which also results in a feasible system; however it also means that some energy remains unused. Whilst for the energy balance becoming negative, the energy demand of the system can no longer be provided within the system, and external energy sources would need to be provided, which leads to infeasibility for a stand-alone system.

However, although all pairs (m_1 | m_2) in the green and orange area of Figure 6-4 provide a feasible system, it should be considered that an optimised system will be restricted to the green area only. For example, the pair chosen as the base case B1 of the modelling analysis in section 6.1 (11tonnes/day of manure | 112.5kg/hr of wood) is shown in Figure 6-4 as the small white dot named ‘B1’ and is located in the green area, which means that this size combination results in an optimised system. Should a higher amount of wood and/or a lower amount of manure be used, then the point would move into the orange area; this would still result in a feasible system, but significant amounts of energy would be wasted, as the energy demand is below the energy supply. Such a system should only be employed if plenty of biomass is available and if energy optimisation becomes a less important consideration over others, e.g. waste disposal.

Once a feasible pair of biomass intake (m_1 | m_2) has been chosen, the resulting production rates of biogas and producer gas can be estimated on the basis of Figure 6-5, which is a result of the sizing studies undertaken in section 6.1 above and is based on the feedstock intakes shown in Table 6-I.

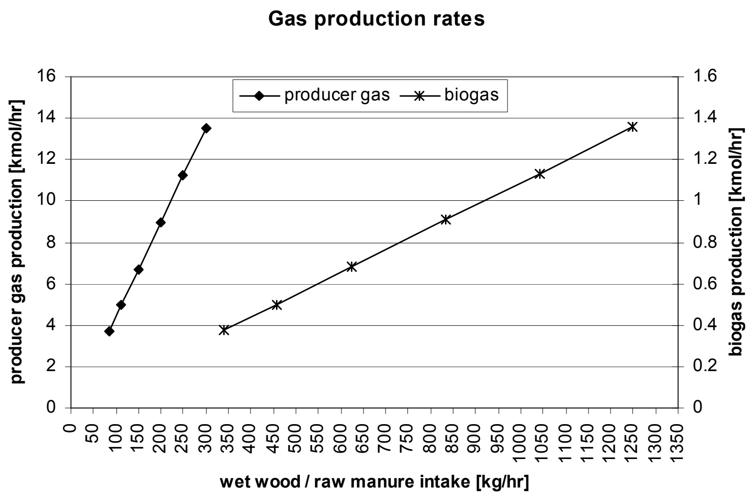

Figure 6-5: Producer Gas and Biogas Production Rates.

Knowing the producer gas and biogas production flow rates ($\dot{V}_{FUEL}$) that result from the chosen feedstock intake, the available turbine power level (P_{EQ}) can then be estimated by using the aforementioned lower heating values for the two fuel gases (LHV_{FUEL}) to calculate the microturbine energy input. Using the microturbine efficiency shown in Figure 4-15 (η_{MT}), the available turbine power level becomes

$$P_{EQ} = \eta_{MT} \cdot LHV_{FUEL} \cdot \dot{V}_{FUEL} \,. \tag{6-8}$$

As the gas production rates are continuous, this resulting turbine power level would however be the equivalent level that a turbine could be operated on continuously. Instead, the plant will be running flexibly to accommodate load fluctuations, and the microturbine will be operated between 50-100% of its nominal power level, as discussed above. This means that a microturbine power range has to be estimated on the basis of the overall operational load factors for the continuous flexible operation of the plant. This is demonstrated in the example in Figure 6-6 below.

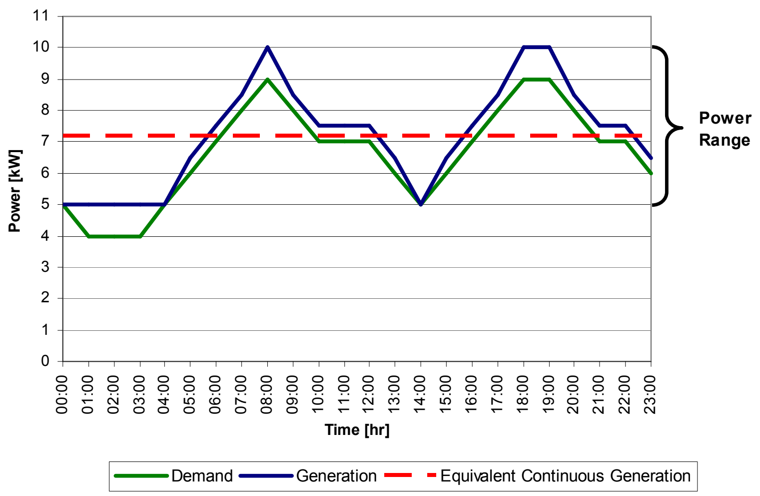

Figure 6-6: Generation and Demand Example.

To match generation and demand for a given set of load profiles, the microturbine will be operated on different load levels during the course of operation. The maximum and minimum microturbine load levels constitute its power range and will depend on the load profile characteristics, which for real load profiles will be discussed in more detail in chapter 7. The example in Figure 6-6 shows both demand and generation, and the minimum and maximum microturbine power levels would be 5kW and 10kW, respectively, resulting in a power range of 5-10kW in order to meet demand. The total amount of power generated (P_{GEN}) during the whole operational period when following the operation cycle can be calculated as

$$P_{GEN} = \int P_{ACT}(t)dt \ \text{[in kWh]}, \tag{6-9}$$

i.e. as the integral of the actual microturbine output power function (P_{ACT}) over the time, or as the area under the generation curve in Figure 6-6. This value can then be transformed into an equivalent continuous generation (P_{EQ}) through

$$P_{EQ} = \frac{P_{GEN}}{\Delta t} \tag{6-10}$$

with Δt being the operational period. This continuous generation level is shown in Figure 6-6 as the dashed line.

For a given real load, once a range of microturbine power levels has been established, a final analysis needs to evaluate whether the microturbine exhaust heat stream can provide sufficient energy to the gasification system and the dryer. Operating the microturbine on different load steps influences the amount of its hot exhaust gas stream, which is used as the heat carrier for both the gasification heat exchanger and the wood dryer. Therefore it needs to be ensured that sufficient exhaust heat is available to cater for the continuous gasification process. This analysis was again undertaken as a two-variable approach to analyse the energy balance of pairs of turbine output and wood intake. Its results are shown in Figure 6-7 in a similar area chart where the traffic-light system is again employed to indicate the feasibility of the system.

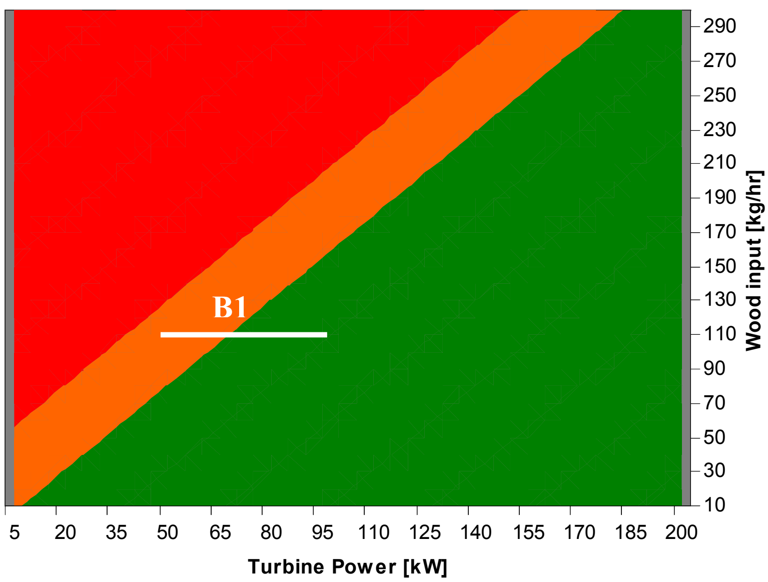

Figure 6-7: System Energy Balance for Pairs of Turbine Power and Wood Intake.

For a given wood intake, the turbine power range which can provide sufficient energy is shown in the green area (positive energy balance – feasible); the power levels that result in insufficient exhaust heat for the process are shown in the red area (negative energy balance – infeasible); and the orange area shows the power range for an energy balance in equilibrium.

The power range of the base case as defined above (50-100kW) is shown in Figure 6-7 as the white line named 'B1'; its lower turbine power levels are in the orange area, which means that the operational range of the turbine is optimised energetically.

6.2.5 Feedstock Availability Analysis

The plant size needs to be tailored both to the available feedstock and to the customer demand. Whilst the latter will be analysed in section 7.1, sourcing sufficient feedstock for ongoing power generation and on a local basis is equally essential for self-sufficient energy provision. An analysis of the amount of available feedstock therefore needs to be undertaken in order to evaluate whether it can provide a sufficient generation potential.

Two main points of departure for such an analysis are possible: either the feedstock availability on site defines the amount of power that can be provided, which is the case when feedstock is the limiting parameter; or the peak power defines the amount of feedstock to be used, which is the case when the availability of feedstock is uncritical. The latter case can be treated with ease: the overall peak total power demand on the basis of load profile analysis as discussed in chapter 7 below will determine the size of the power plant, as the plant will need to provide this maximum peak total energy demand. Once this power level is known, the plant can be sized using any feasible combination of the two (wet and dry) feedstock sources shown in Figure 6-4.

If feedstock availability however is limited, it needs to be evaluated whether sufficient power can be sourced from this available feedstock to meet local demand. This means that for ongoing operation, the total amount of power to be drawn needs to be estimated. This will be discussed in detail below, however the result will be a power range as shown in the example in Figure 6-6. Based on the average utilisation factor which follows from the load profile characteristics, it can then be evaluated what power has to be provided for the equivalent continuous generation, see also Figure 6-6. This power forms the energy level that needs to be provided by the conversion technologies in order to enable the generation unit to be operated in the chosen power range. For a certain operation period of, for example, one year, the energy to be provided by the conversion processes can be calculated as

$$E_p = P_{EQ} \cdot t \tag{6-11}$$

with P_{EQ} [in W] from eqn. 6-10 being the equivalent continuous generation, t [in s] being the operation period and E_p being the amount of energy [in J] that needs to be provided by the feedstock for this period. The energy for the generation unit will be provided by means of fuel gas, the aforementioned mixture of biogas and producer gas. This means that this energy can basically be provided by any combination of both wet and dry feedstock, as long as the plant operation limitations discussed earlier in this section are observed.

Choosing this combination will depend on the local availability of feedstock to be used for ongoing power supply, so it needs to be estimated what amount of feedstock can be sourced on a continuous basis. The availability of animal manure and wood chips as examples for both wet and dry feedstock categories will therefore be analysed as follows.

6.2.5.1 Animal Manure

The amount of animal manure that can be utilised for anaerobic digestion depends on a number of parameters. The head size of a livestock herd is one critical value that directly influences the amounts of manure. The housing condition of the livestock and the manure storage prior to digestion are other main factors. For cattle, pig and sheep livestock, housing can be limited to the winter season, which means that manure availability in summer is low due to outside grazing. On the contrary, poultry is normally held inside or within a small confined outside area where manure collection is relatively easy, therefore it can be collected throughout the year. With regards to storage of the manure, it has to be differentiated between livestock keeping with manure collection throughout the year, where storage will be limited to a number of days, and livestock keeping with extended grazing periods, where manure needs to be stored for long periods of time to bridge these gaps in manure collection. When storing manure, decomposition processes occur, and self-heating effects can decrease the energy content of the biomass [36, 157]. Therefore, when manure collection throughout the year is impossible, it needs to be evaluated what amount of manure can be provided year-round, how its consistency is impacted by storage, and which storage needs to be implemented.

Average manure amounts per head and day for confined livestock keeping can be found in literature [36, 90, 158], and are shown in Table 6-VIII. Manure in this context includes faeces, urine, bedding material and fodder residues, and values shown are on a wet basis with a Total Solids content of 45% for poultry and 25% for all remaining livestock [36].

Table 6-VIII: Manure Amounts from Livestock Keeping [kg/d per head].

Cattle	Horse	Pig	Sheep	Poultry
50	23	5	4	0.5

Based on these raw manure ‘production rates’ per head, a conversion rate into biogas can be calculated as shown in Figure 6-5 above. Using this resulting biogas rate, the calorific value of biogas as mentioned above, and the generation efficiency of the microturbine, a potential for power generation can be calculated. It can thereafter also be computed how many head units are necessary to continuously generate $1kW_e$. This result is shown in Table 6-IX, and it can then be used to match the continuous equivalent generation P_{EQ} from eqn. 6-11 with a combined livestock herd of a fitting size.

Table 6-IX: Generation Potential from Livestock Keeping [number of heads/kW].

Cattle	Horse	Pig	Sheep	Poultry
7	12	55	70	310

From this follows that for a continuous equivalent generation of ***A*** kW, which will be met by ***B*** % wet and ***(100-B)*** % dry feedstock, the equation

$$A \cdot \frac{B}{100} = \frac{C}{7} + \frac{D}{12} + \frac{E}{55} + \frac{F}{70} + \frac{G}{310} \tag{6-12}$$

can be used to compute the number of cattle (C), horses (D), pigs (E), sheep (F) and poultry (G) necessary to provide sufficient manure for the wet biomass part.

6.2.5.2 Wood Chips

Wood chips as an example for dry feedstock can be made from wood residue, forestry waste, tree logs or Short Rotation Coppice (SRC). Once the raw wood feedstock is collected, it is chipped and dried before gasifying it for conversion into producer gas.

Whilst waste wood (such as old building material) can be an interesting source for wood chips, in general it will lead to issues with paint and other residues which impact conversion and generation technologies [14]. Additionally, waste wood itself is not a renewable resource in the context of this project and continuous supply would need to be ensured. In comparison to that, tree logs can be used for high-quality residue-free wood chips. However, with a perspective of decentralised power generation, it again would not be realistic to use tree logs for wood chip production, given the time necessary for tree growth and thus the lack of regeneration for ongoing supply. Both waste wood and tree logs were therefore not deemed suitable sources for the plant design in this project, and instead the main focus was laid on wood residues and SRC, as they are also mentioned as the most likely used fuel source in remote and rural regions [159].

Forest residues are the result of natural or artificial thinning of forests, a process that removes some of the trees to allow the remaining to grow more efficiently. Forest residues thus consist of tree branches and leaves of larger trees and smaller trees that died due to the thinning process. Other sources of forest residues are wind damaged trees or simply aged trees at the end of their life cycle. As all these processes occur continuously, forest residues can be collected continuously and are therefore a suitable source for ongoing wood chip supply.

Due to its nature, there is no set yield for forest residues; however, for a given surface area of forest, average annual dry matter yields have been reported in literature [14, 160], and it can therefore be estimated what amount of forest residues is available once the surrounding forest area is known. Table 6-X provides a conservative range based on the aforementioned literature.

Short Rotation Coppice is a process using managed coppice cultivation for energy purposes. Numerous energy crops exist and are currently investigated due to their potential of becoming more conventional fuel sources, however for SRC mainly willow and poplar are used. During energy cultivation, they are planted in rotation on parts of land depending on their harvesting period, which ranges from every two to four years [161]. Especially the fast growth and comparably easy harvest of SRC together with their continuous supply due to short rotations make them an ideal source for wood chips, combined with very little attention being necessary during growth.

Numerous publications have discussed achievable yields of different SRC cultivars and under different circumstances, such as irrigation periods, soil quality, temperature and season etc. Although significant fluctuations in yields have been reported, a reasonable average range is shown in Table 6-X below, based on available literature [18, 159, 161-166].

Table 6-X: Forest Residue and SRC Annual Yields [$kg_{dry}/ha \cdot a$].

Forest Residues	SRC
1,400-2,300	6,000-15,000

On the basis of these dry annual yields per hectare, and by using the conversion rates of dry biomass to producer gas as shown in Figure 6-5, expected producer gas quantities can be calculated. Similar to chapter 6.2.5.1 above, by applying the calorific value of producer gas and the generation efficiency, it can then be calculated what surface area provides sufficient feedstock for an equivalent continuous generation capacity P_{EQ} of $1kW_e$. These values, which are shown in Table 6-XI, can then be used to calculate the surface area necessary for sourcing sufficient feedstock for a given generation capacity.

Table 6-XI: Generation Potential from Forest Residues and SRC [ha/kW]

Forest Residues	Short Rotation Coppice
3.75-6.25	0.58-1.46

It can be seen that the given range is relatively broad, which again is caused by the nature of this energy source. Since the mentioned values are a relatively conservative estimate, by calculating a needed area for both the upper and lower limit shown in Table 6-XI it can be estimated whether both best and worst case of high or low biomass growth could provide sufficient feedstock for generation.

In this chapter it has been proven that the chosen plant design results in a feasible and suitably sized power plant model. The outputs of the single units were found to be in line with results of operational plants and thus indicate the validity of the chosen modelling parameters. By comparing the energy balances of the main plant units anaerobic digester, gasifier and microturbine, a feasible size range of the combined system was developed. Finally, the feedstock availability analysis has provided a comprehensive understanding of the relation between available feedstock streams and resulting maximum power plant size.

Since it was found that the plant can be scaled down to an output that suits a small group of domestic customers, the following chapter will evaluate their expected power demand in detail, and will provide the operational analysis of running the plant to supply this load.

7 Load Profile Analysis and Simulation

The plant has been designed to provide power to a group of domestic customers, such as in a small remote village. When providing these customers with decentralised electricity, especially if independent from a grid connection, a main issue which needs to be analysed is how to facilitate ongoing security of supply. As was already discussed in chapter 1, power demand fluctuates significantly over the course of the day, so in order to match demand and supply the plant needs to meet the actual load characteristics of the customers, especially when no electric storage is intended. It is therefore essential to fully understand the load profile patterns and characteristics of the target customers and to use realistic demand data for simulations in order to evaluate whether successful operation can be achieved.

The first part of this chapter will describe in detail the load profile analysis which was undertaken to understand the load profile patterns and characteristics and to achieve realistic and useable load forecasts for the simulations to be undertaken. In the second part of this chapter, extensive plant operation simulations on the basis of these load profiles will be performed and the results will be described.

7.1 Load Profile Analysis

In order to assess and evaluate what levels of power the plant will need to provide to the customers, it needs to be evaluated which demand patterns and characteristics are likely to occur in operation. This means that it is necessary to understand the relationship between power demand and time, and the likely level of fluctuations of demand. This knowledge of demand or load patterns and characteristics is described by the term ‘load profiling’.

A load profile is the electrical demand (or load) of a customer (or a group of customers) as a function of time [5]. It shows what power is drawn by the customer at each time interval, at what point of time the load demand peaks, slumps, etc., and therefore depicts the patterns and characteristics of load demand, generally over a longer period of time, i.e. the course of a day. Since the demand for electrical power is not constant, load profiles are necessary to forecast which amount of power will be requested at which point of time. Using realistic load profiles, it can then be evaluated and determined which plant power level needs to be set in order to meet demand.

Load profiling is a well-known method in power engineering, however obtaining suitable load profiles of a fitting size for the plant in this project is a highly challenging task. Whilst the aggregated load profiles for whole nations and large grid systems are easily obtainable[7], this is not the case for useable and detailed domestic customer load data. In general, at the individual customer level load data is obtained by measuring the demand of a representative population group, which normally requires the permit of the respective utility. Restrictions on publication of these load data is normally put in place, as they are classified as proprietary by the utilities. Therefore, without a utility willing to provide load data for suitable clusters of their distribution network, the only ways to obtain load data are by using the few published sources or through simulation, which estimates customer loads.

However, as this project is focused on providing power to a group of domestic customers, and especially without a grid connection to level out demand and supply, a high-resolution load profile is necessary in order to understand the general medium- to long-term patterns, as well as the transient behaviour and fluctuations within very small periods of time. As load profiles in general are measured in 30-60 minute intervals [5], openly accessible load data in higher resolution is very rare.

A very detailed data source for residential load profiles which is deemed both useable for the intended simulation studies and appropriate in means of real underlying data has been the publication of residential load profiles from the International Energy Agency 'ECBCS Annex 42 Subtask A' research project, which includes both individual residential load curves and the load profiles of a group of residential customers [167, 168]. This data has a resolution of 5min, which is by far the most detailed openly accessible source. In this section it will be explained why the data is realistic, why it can be used for the simulation studies to be undertaken, and whether the measurement methodology will be a valid approach. Thereafter, this data will be used for the plant operation simulations.

[7] For example, the aggregated current and historical demand data for Great Britain can be obtained from National Grid, the Transmission Network Operator (TNO) of Great Britain, through their website (www.nationalgrid.com); see also Figure 1-4.

A transient analysis will then complement the analysis and simulations of this section and will prove that the load and operation patterns are a valid assumption for the operation. Further evaluations on the basis of high resolution detailed transient load profiles from simulation will then be undertaken as part of the off-grid analysis in chapter 8.

7.1.1 Individual Domestic Load Profile Patterns and Characteristics

The load profile of a single domestic dwelling can be described as a very low constant load combined with a random aggregation of very high power spikes [5, 168, 169]; Figure 7-1 [168] depicts the power demand of an actual household in Newcastle (United Kingdom) for a randomly selected period of four consecutive days in February 2005[8]. The random power spikes which are characteristic for single dwelling load profiles, and which can easily be seen in Figure 7-1, follow from the fact that electrical appliances are the main power consumer in individual households. Those appliances cause the high power spikes on an intermittent basis: they are switched on and off, but without giving prior notice and without following a fixed pattern. It is therefore impossible to exactly forecast an individual load profile and the timing of its power spikes [5].

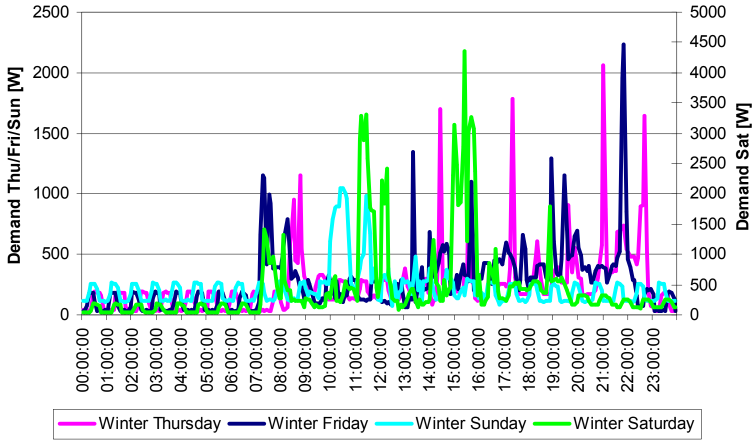

Figure 7-1: Individual UK Household Load Profiles (Source: adapted from [168]).

[8] For improved readability, the load profile for Saturday was plotted on the secondary y axis due to its higher absolute values, whilst the Thursday, Friday and Sunday profiles were plotted on the primary y axis.

Whilst the individual domestic load profile is highly randomised and cannot be forecasted, combining individual households and their energy demands into a group strongly influences the resulting load profile characteristics. This means that for a group of dwellings, the resulting load profile, i.e. the combined power demand of all dwellings within this group, strongly differs from multiplying the single load profile with the number of households in the group. As mentioned before, the exact timing of power spikes in an individual load profile is random and cannot be forecasted. However, two individual households will have two different time lines of power spikes, which again follows from statistics and from the fact that no two households have the exactly same power demand patterns. Whilst at one second of time one household might draw its maximum power, another household might not need any power at all; and vice versa at the next second [5].

The result of this behaviour is that with an increasing number of households within the group, a smoothening and flattening process of the resulting load profile occurs due to interlacing of the individual power spikes. This effect is shown in Figure 7-2 and Figure 7-3 [5], which depict the winter weekday load profile for a single household in a suburban area in the United States of America, as well as the resulting load profiles for groups of two, five, 20 and 100 households[9]. Whilst it is nearly impossible to forecast the power spikes of an individual household, it becomes more and more predictable for a rising number of dwellings in a group.

[9] It should at this point be noted that the maximum load per dwelling in Figure 7-1, with around 4.5kW for Saturday or 2.5kW for weekdays, is significantly below the respective value in Figure 7-2, with around 12kW, although both profiles are for the winter season. This however can be explained by the fact that Figure 7-1 depicts the demand of a flat in the UK whilst Figure 7-2 depicts the demand of suburban houses in the USA, which have a significantly higher power demand. In addition, Figure 7-2 includes power consumption of a whole-house heat pump whilst the profiles in Figure 7-1 are exclusive of space heating [5, 168, 170].

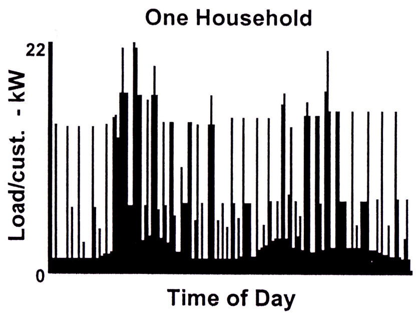

Figure 7-2: Individual US Household Load Profile (Source: [5]).

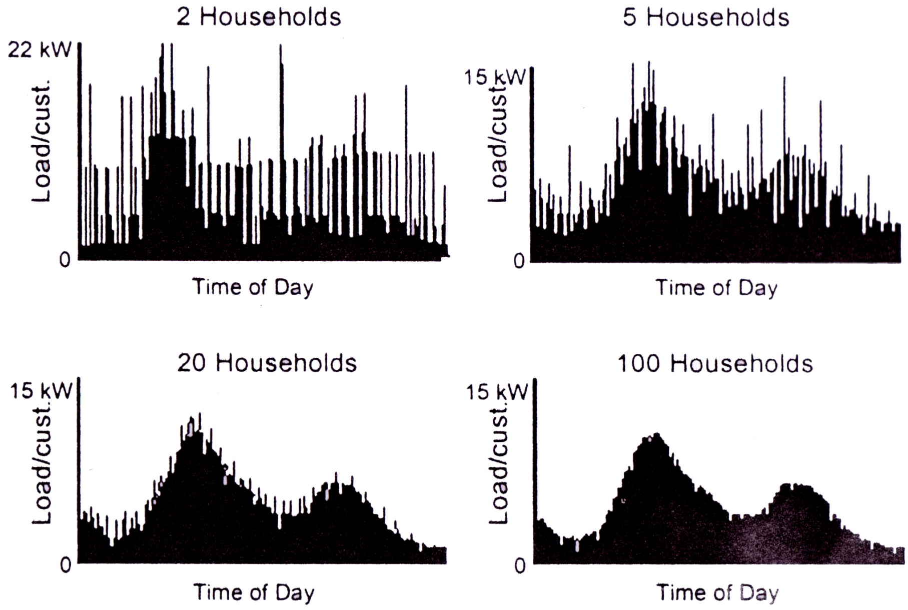

Figure 7-3: Load Profiles of Groups of 2, 5, 20 and 100 US Households (Source: [5]).

This however provides a significant benefit for load operation: whilst it is close to impossible to forecast the power demand of an individual household on the basis of its load profile and therefore power supply cannot be based on this assumption, it becomes more and more feasible to utilise the load profile of a group of households as an appropriate forecast of their real power demand characteristics, depending on the number of households in the group. For groups of around 50-100 dwellings, the resulting load profile can be deemed as sufficiently flattened to be used for operational analyses [5, 170].

The aforementioned is however another important limiting factor that needs to be considered when providing decentralised power generation to domestic customers independent from the grid. In addition to the minimum plant size that has been established in the analysis in section 6.2 above, a minimum number of households needs to be available to supply the generated power to. This means that a group of at least 50 households need to exist as possible customers of the plant in order to be able to analyse the characteristics of demand and to set up a suitable group load profile. The actual size of the group will be determined in section 7.2.1 below, however this minimum size will need to be provided for.

7.1.2 Group Load Profile Data and Characteristics

On the basis of the findings of the previous section, it was decided that feasible and realistic load simulation can only be undertaken for a group of domestic customers. Therefore, the respective realistic load profiles of a group of fitting size for the purpose of this project need to be analysed. The aforementioned load profile data published by the 'IEA/ECBCS Annex 42 Subtask A' research project [167] was found to be a sufficient and useable source with regards to both realistic underlying data and a fitting size of the analysed group, as will be discussed in this section; it was thus decided to use this load profile data as the basis for the simulation studies to be undertaken in this project.

The datasets provide the average per-dwelling five-minute interval load demands (in Watt) based on a group of 69 residential UK dwellings which were monitored between 2002 and 2005. This means that for every five minutes, a data point provides the average power demand drawn during this period by all the houses, divided by the number of houses in the group. The datasets are exclusive of space heating and consist of pure electricity demand. The measuring was undertaken during a three-year period, and flats, town-houses as well as semi-detached houses were included in the group [167, 170].

The data is presented on a 24 hour time basis and is differentiated by weekday/weekend and season. Three seasons were determined: winter (December – February), summer (June – August) and two shoulder seasons covering the remaining months of the year [167, 170].

The applied method of load measurement is called *period integration*, since for each interval of time (*period*) the total power drawn, i.e. the *integral* of actual demanded power over time, is recorded and provided. An alternative method of measuring is called *discrete instantaneous sampling*, which measures the actual demanded power at the beginning of each interval [5]. In order to evaluate whether the applied methodology can be deemed appropriate for the intended simulations, Figure 7-4 provides an example to demonstrate the differences between the two measurement methods.

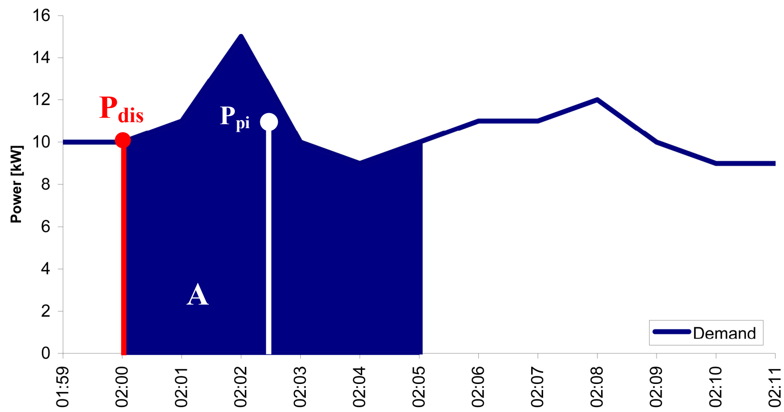

Figure 7-4: Demand Example and Demand Measurement Methods.

The blue line in Figure 7-4 is an example of an actual demand between 01:59 and 02:11. This means that the actual power demand P_{DEM} is a function of time and can be defined as

$$P_{DEM} = f(t) \text{ [in kW]}. \tag{7-1}$$

The blue area named '*A*' in Figure 7-4 depicts the integral of the actual power demand for the time interval 02:00-02:05, i.e.

$$A = \int_{t=02:00}^{02:05} P_{DEM}(t)dt \text{ [in kWs]}. \tag{7-2}$$

Should the power demand P_{DEM} be measured through *period integration*, a resulting power P_{pi}, shown as the white point in Figure 7-4, would be provided as

$$P_{pi} = \frac{A}{\Delta t} \text{ [in kW]}. \tag{7-3}$$

This means that the actual power drawn would be recorded over the whole time interval, and a value which represents the average drawn power would be provided.

Should P_{DEM} be measured through *discrete instantaneous sampling*, a resulting power P_{dis} would be provided, which is shown as the red point in Figure 7-4 and can be calculated as

$$P_{dis} = P_{DEM}\,(t = 02:00)\ \text{[in kW]}. \tag{7-4}$$

This means that the actual power demand at the beginning of the time interval would be provided. At this point it becomes apparent that this value does not represent the actual power drawn throughout the time interval, but instead provides one randomly chosen value of power drawn during the time interval, which can be above, below or exactly at the average value.

Therefore, obtaining load profile data through *period integration* is mentioned as the only suitable and valid methodology for the purpose of load analysis and simulation, as long as the length of the time interval, i.e. the load profile *resolution*, is chosen adequately [5]. This constraint follows from the fact that for very long time intervals or low resolutions, the average value provided through *period integration* can hide demand peaks; it is therefore necessary to sample often enough in order to provide a realistic picture of the real demand. With regards to the aforementioned flattening effect of load profiles from an increasing group size, it has been mentioned that a resolution of 15min is adequate for a group of 100 customers [5]. From this follows that the 5min resolution of the present load profiles, which represent a group of 69 households, can be deemed appropriate, and that the load profiles thus provide a realistic picture of the real demand.

Figure 7-5 shows the respective load profiles for the six cases, and as mentioned before, significant load level differences can be found for the three seasons and between weekdays and weekend days.

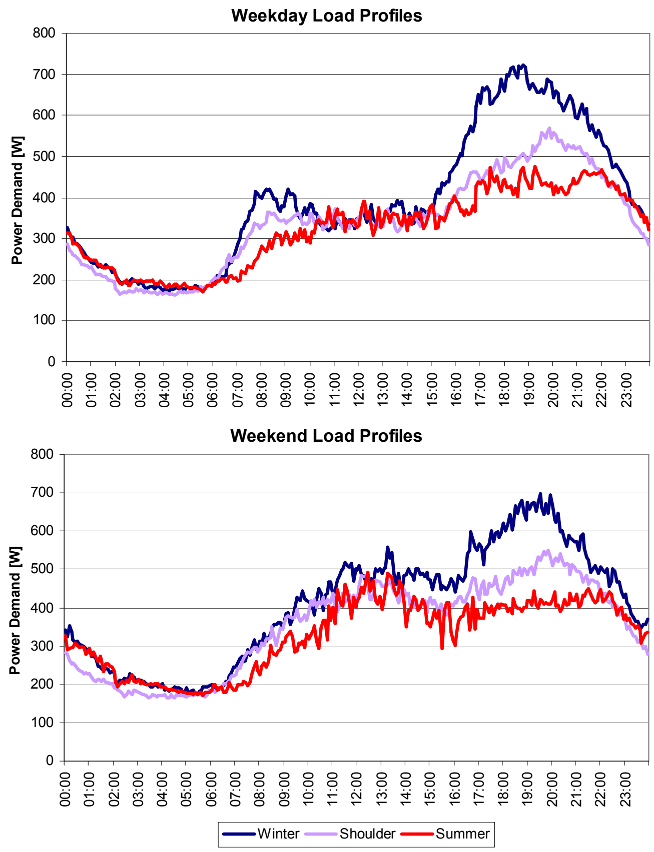

Figure 7-5: Seasonal Weekday and Weekend Load Profiles.

During the weekdays, two main peaks occur, which correlate with the working time of dwelling inhabitants, and night-time demand for electricity is lower than day-time demand. In contrast to that, a shifted demand pattern occurs on weekend days, and a less distinct morning peak can be found. A relatively steady increase in the demand for electricity from the morning to the evening levels can be seen, and again the night-time demand is significantly below the day-time demand. As mentioned above, these trends were expected and are mainly caused by occupancy patterns [3, 5, 169-171]; they are well-known in load profiling research and thus indicate the usability of the data.

Discussing seasonal differences, the power demand is considerably higher in winter times than during the summer, especially during weekdays. Whilst the intra-day patterns remain on a comparable basis within the seasons, their absolute level changes significantly. However, this result also has to be expected, as lighting demand or use of cookers increases during the cold seasons [169-171].

Since the data was collected in 2002-2005, a comparison to current absolute demand levels is necessary to further prove whether the data is realistic and useable. For example, the average UK domestic electricity consumption has risen by 2.0% for the period 2002-2005, and fallen by 1.5% for the period 2005-2007 [172]. Current absolute domestic electricity demand might thus be on a different level than provided in the source files. In addition, it has been pointed out above that absolute levels are different for different household types (e.g. flat, apartment, house) and regions (e.g. UK, Europe, USA).

These points notwithstanding, general demand patterns will still remain the same, even if on different absolute levels. Since the focus of this section is to analyse the ability of the plant to cope with load patterns and fluctuations, the demand patterns that are represented by the data are still valid and useable for the simulation purposes. In addition, a different absolute demand level can easily be accommodated by increasing or decreasing the absolute power output level of the plant accordingly. It was thus decided to use the original load data for the simulations to be undertaken, without manipulating it.

7.2 Load Simulation

After having demonstrated in the previous section that the load profiles are a suitable model of real demand, this section will provide proof that the plant is able to generate depending on the load, and that it is able to accommodate load fluctuations to facilitate continuous power supply to the customers.

7.2.1 Simulation Setup

In order to set up the simulation, both a suitable plant size and a fitting number of households need to be defined. Since the load profiles described above are on a proportionate per-dwelling basis, a group of individual residential customers needs to be created to supply power to; however, the restrictions with regards to a minimum group as mentioned in section 7.1.1 above need to be taken into consideration. On the other hand, the technological size limitations described in section 6.2 also require a certain minimum size of the plant.

After comparing the total net power output level of the minimum plant size, defined as the ‘base case B1’ in section 6.1, with the power demand of the proportionate per-dwelling load profiles, and including suitable buffers for power increases as will be described below, it was found that the base case plant size established in section 6.1 will be able to accommodate the power demand of 120 individual households. To achieve the group load profile, each individual proportionate per-dwelling data point was thus multiplied by the number of dwellings in the group, i.e. by 120.

After having achieved the group load profiles, it was evaluated how the power generation can be governed in order to match demand and supply consistently and reliably, and a number of generation algorithms were evaluated. On the one hand, generation needs to be at least at the power level of demand, and this becomes critical as demand can change significantly within short periods of time, so a buffer needs to be implemented to cover instantaneous demand increases. On the other hand it is necessary to minimise generation in order to use resources effectively and to not generate significantly above the demand, since this 'excess generation' needs to be sunk within the plant.

Given the significant power range of the load profiles, it becomes apparent that at least for some periods of time the power plant needs to be operated on output levels below full nominal power, so a number of power steps need to be set. A minimum power output of 50% of the nominal turbine power was chosen, as this level was found to be the minimum level at which microturbine generation can still be achieved in an effective and stable manner, as discussed in section 4.3.2.1 above. This means that this plant will be operated on between half and full nominal turbine output power in order to follow the load. Based on the maximum load profile demand and including sufficient buffers for fluctuations, a nominal power level of 100kW was established, which in turn means that the minimum power output will be 50kW, and that the power range (as defined in Figure 6-6) is therefore 50-100kW. As mentioned above, these levels also correlate well with available microturbine power technology.

The area within the power range can then be divided into a discretionary amount of intermediate power steps in order to minimise the difference between generation and demand; however, more steps mean that the turbine will need to be adjusted more often. As each output power adjustment will influence the operation stability and will require some time, there will be a trade-off between the number of steps and their impacts on the operation. Additionally, as mentioned above, the microturbine needs around 20-30s to adjust to a new power level, hence infinitesimal power adjustment steps are not realistic. Through analysing and minimising the offset power and using sufficient buffers, which will be discussed below, it has been found that three steps, at 65kW, 75kW and 85kW, provide both an energy efficient and reliable operation pattern. This concludes that in the following load simulations the microturbine can be operated on power outputs of 50, 65, 75, 85 and 100kW.

7.2.2 Generation Power Range Analysis

Before simulating the load profile operation on the basis of the chosen power range, in a final step it was evaluated whether and how the power range impacts the plant operation and especially the conversion technologies of the plant.

Both conversion parts of the plant (gasification and anaerobic digestion) need to be operated on a constant and continuous level to enable the ongoing bacterial AD processes, and to maintain the gasifier temperature distribution. This however means that producer gas and biogas production are continuous processes that will not depend on the microturbine power output levels. Since the plant design uses heat streams internally, i.e. for its own processes, it is necessary to understand the impact on the plant when adopting several power output levels whilst keeping the conversion rates constant.

The output power of the microturbine depends on the amount of fuel gas which is fed to the turbine. As mentioned in the modelling section 5.2 above, the microturbine air intake is calculated on the basis of the fuel gas flow, so this will change accordingly when adopting different power steps. This change in air intake mainly impacts the microturbine heat exchanger, which uses the producer gas exhaust heat stream to preheat the microturbine combustion air. An increase of air intake in the air compressor will mean that the heat exchanger will also be operated on a higher air mass stream. This effect is shown in Figure 7-6, which depicts the microturbine (MT) air flow as a function of the MT power output.

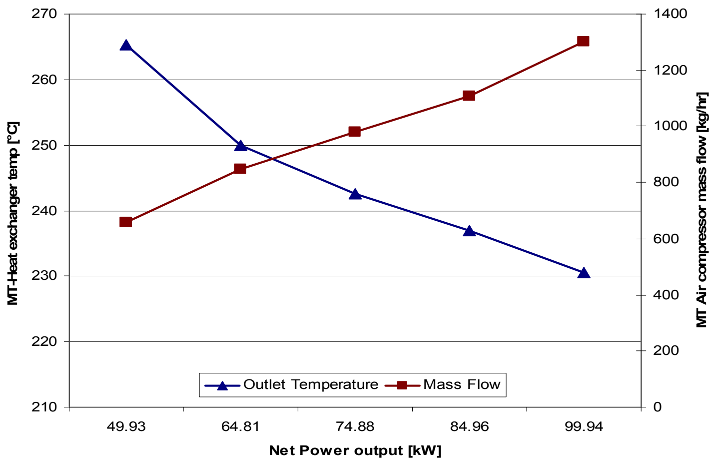

Figure 7-6: Power Range Variation Impacts.

As the heat exchanger has a set geometry which does not change when more air is flowing through it, the amount of heat to be exchanged between the air stream and the producer gas stream will remain relatively constant. This however means that a higher air stream will lower the MT outlet temperature, which is the air temperature after leaving the MT heat exchanger. This effect is also shown in Figure 7-6.

It can be seen that while the air mass stream increases with increasing power output, the hot air output temperature decreases. However, its absolute level, from 265°C for half nominal load to 230°C at full load, does not influence the microturbine operation significantly, since the combustion chamber still provides sufficient levels of thermal energy for the exhaust gas to reach its maximum temperature level.

Other main plant parameters have also been evaluated and it was found that all parts of the plant can cope with the desired power range. Therefore, the microturbine operation on the chosen power steps is feasible, which means that this power range can be used to match demand in the load profile simulations of the following section.

7.2.3 Load Profile Demand/Generation Simulation

For each of the six profiles that were discussed above, the daily demand patterns were rounded up to the next multiple of 5kW and are shown in Figure 7-7 as the orange areas.

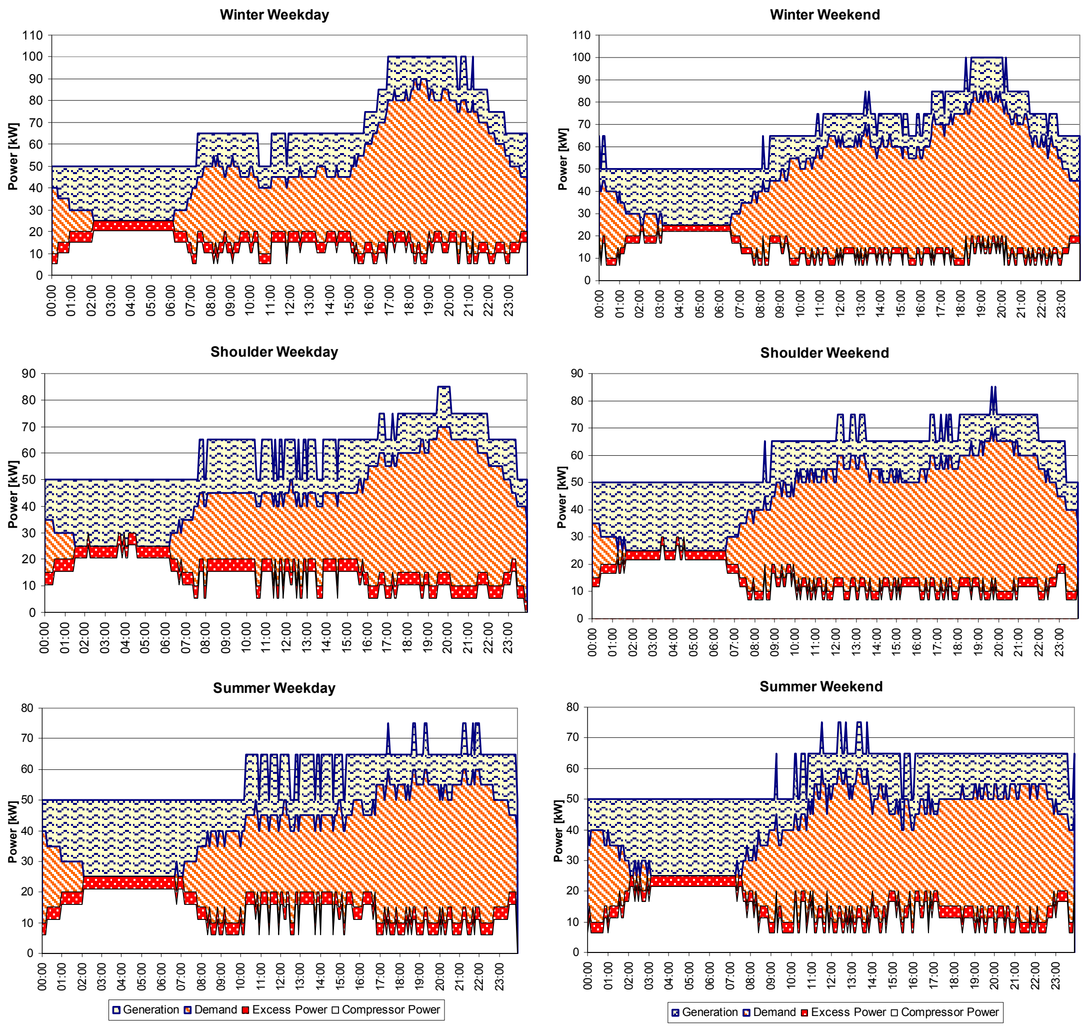

Figure 7-7: Demand/Generation Simulation Results.

Afterwards, the microturbine output power P_{MT} was set to its respective power step of between 50 and 100kW for each of these rounded-up demand data points P_{DEM_R}, by using the following control algorithm which was found to provide best results, i.e. the minimum amount of 'excess generation' combined with sufficient buffers to accommodate fluctuations:

$$\begin{array}{lcl} P_{MT} = 100 & & P_{DEM\_R} + 10 > 85 \\ P_{MT} = 85 & & P_{DEM\_R} + 10 > 75 \\ P_{MT} = 75 & for & P_{DEM\_R} + 10 > 65 \\ P_{MT} = 65 & & P_{DEM\_R} + 10 > 50 \\ P_{MT} = 50 & & P_{DEM\_R} + 10 \le 50 \end{array} \qquad (7\text{-}5)$$

This microturbine output power is also shown in Figure 7-7 as the yellow areas.

The *Winter Season* weekday and weekend profiles are of the highest criticality with regards to their absolute level, thus they were analysed first. It can be seen in Figure 7-7 that the night-time demand falls sharply to levels of 25kW, whereas the evening peaks reach values of up to 90kW for the weekday and 85kW for the weekend case.

The power difference between the demand curve and the generation curve needs to be used within the process since no electric storage is implemented. However, the fuel compressor needs a certain amount of power (P_{COMP}) to compress the producer gas/biogas mixture to the pressure level demanded by the microturbine. Additionally, the electric heater can also use *'Excess Power'* (P_{EXCESS}) by converting it into thermal energy to dry the feedstock. This means that compressor and electric heater act as productive power sinks of the plant in order to always achieve the necessary match between demand and generation, which can be expressed as

$$P_{DEM\_R} + P_{COMP} + P_{EXCESS} \overset{!}{=} P_{MT} \tag{7-6}$$

As discussed above, the fuel gas conversion rates remain constant, resulting in a constant output of uncompressed gas mixture which needs to be compressed. This would require P_{COMP} to become a constant. However, there is no immediate necessity to compress this gas as long as storage is available, and this is why the fuel compressor can become a tool to match supply and demand: instead of running on continuous power, it is operated on different power levels depending on the amount of power available.

As long as the whole gas amount is compressed during a longer overall period, such as one day, and as long as sufficient storage capacity is implemented, the microturbine will always have sufficient compressed fuel gas to provide the demanded power levels. Since variable operation of the compressor was found to significantly improve the possibility to match supply and demand, it was chosen to accept the additional cost of uncompressed gas storage and to implement this variable compressor operation. The respective compressor power levels, as well as the remaining *Excess Power* to be used in the electric heater, are also shown in Figure 7-7 as the white and red areas, respectively.

It can be seen that P_{COMP} fluctuates between 5.3-20.3kW for the weekday and between 7-22kW for the weekend profiles. The resulting absolute value of P_{EXCESS}

indicates the criticality of the case, which means that a close match of demand and generation results in a low value for P_{EXCESS}. For both winter cases the value is between 3-5kW, which provides sufficient levels for instantaneous power spikes, as will be discussed below.

Next, the demand patterns for the *Shoulder Season* weekday and weekend profiles will be analysed. Compared to the winter profiles, a significant overall decrease in the power level can be seen. Whilst the maximum demand reaches a level of 90kW for the winter case, it only touches 70kW for a maximum of 30 minutes during the shoulder season evening peaks. Simultaneously, the generation never reaches its full nominal power of 100kW but stays below or at 85kW for both weekday and weekend. The night-time demand during the shoulder season falls to 20-25kW, which is also slightly lower than the respective winter demand. This means that the power range for P_{COMP} increases to 5-27kW. The level of P_{EXCESS} for the two shoulder season cases is also shown in Figure 7-7 and is slightly above the value for the respective winter cases, which suggests that the shoulder season is less critical than the winter season.

Finally, the two *Summer Season* cases will be discussed. Again, the maximum demand level decreases and reaches a maximum value of 60kW for the weekday evening peaks and for the weekend mid-day time. It is interesting to note that the summer season weekends are the only patterns where demand during the day is higher than evening demand, which might be related to a high demand for cooking and an otherwise low demand throughout the day, as mentioned in section 7.1 above.

However, apart from this change of the peak time, the demand profiles are similar, as the differences between daytime and evening are more distinct during the weekends than during the weekdays, and the night-time demands are significantly lower. For the summer period and especially for weekends, a nearly flat power demand can be seen, as the peak loses its distinction.

The generation pattern follows this lower demand and the microturbine power output reaches a maximum of 75kW, which is one power step below the shoulder season maximum and two steps below the nominal power. P_{COMP} is in a range of 6-22kW, which is also slightly lower than in the shoulder season, and P_{EXCESS} is again slightly above the respective winter case value.

To evaluate the utilisation level of the microturbine for each of the six cases, a utilisation or load factor λ_{MT} can be calculated as

$$\lambda_{MT} = \frac{\int P_{ACT}(t)dt}{100kW \cdot \Delta t} \tag{7-7}$$

This compares the actual microturbine power output which is shown in Figure 7-7, i.e. the integral of the actual generation function (P_{ACT}) over the operation period, to a theoretical power output when operating the microturbine on full nominal load, i.e. at 100kW, throughout the operation period (Δt).

The load factors for each of the six cases are shown in Table 7-I. It can be seen that the winter season profiles, which are the cases with the highest power demand, have the highest load factors and reach more than $^2/_3$ of the theoretical full nominal load operation, which is a considerably high value and indicates the optimisation of the system. Due to a decreasing power demand for the other seasons, the load factors decrease accordingly and reach 61% for the shoulder season cases, and 58% for the summer season cases.

For an operation period of one calendar year, an average annual microturbine utilisation factor can be calculated on the basis of allocating calendar days to the three seasons and to weekdays/weekends, which is also shown in Table 7-I. This means that a calendar year consists of one winter season, one summer season and two shoulder seasons, with 65 weekdays and 26 weekend days per season. The overall average utilisation factor for one calendar year can then be calculated as 62.2%.

Table 7-I: Microturbine Utilisation Factors and Allocation of Days per Calendar Year.

Case Name	λ_{MT}	Days per Calendar Year
Winter weekday	67.7%	65
Winter weekend	67.7%	26
Shoulder weekday	61.2%	130
Shoulder weekend	61.4%	52
Summer weekday	58.3%	65
Summer weekend	58.5%	26
Whole Calendar Year	62.2%	364

Compared to conventional power plant designs that aim for a large scale and load factors near 100%, which means continuous flat output at nominal power, lower load factors had to be expected in this project. However, given the very flexible generation patterns and considering that the main intention of the plant is to provide continuous power in order to closely match supply and demand, the achieved load factors are on an acceptable level, and the annual load factor in particular proves that the turbine is not 'under-utilised'.

7.2.4 Storage Level and Charge/Discharge Analysis

Since both the microturbine output power and the fuel compressor input power are variable in order to match supply and demand as described above, gas storage becomes a necessity. Both conversion processes (gasification and AD) create a continuous flow of uncompressed gas, which, before being used as the microturbine fuel, needs to be compressed in the fuel compressor. Since the fuel compressor will be operated on variable load levels, a certain amount of producer gas/biogas mixture needs to be stored in an uncompressed gas storage. Similarly, the amount of gas that is being compressed does not necessarily equal the amount of compressed gas required by the microturbine for each unit of time, so the difference between those two gas amounts needs to be stored in a compressed gas storage.

To analyse sizing issues of both storages and to validate whether the operation pattern described in 7.2.3 leads to an effective operation of the plant, it is necessary to evaluate the storage charge and discharge cycles as well as absolute storage levels that will need to be provided.

For each of the six load profiles, Figure 7-8 shows the absolute levels of both the uncompressed gas storage (before the fuel compressor) and the compressed gas storage (after the fuel compressor) that result from the generation patterns shown in Figure 7-7. The scale of both graphs is m^3, however it should be noted that the pressures are different: Whilst the uncompressed gas storage has an atmospheric pressure, the compressed gas storage is maintained at a pressure of 5bar to satisfy microturbine energy intake requirements.

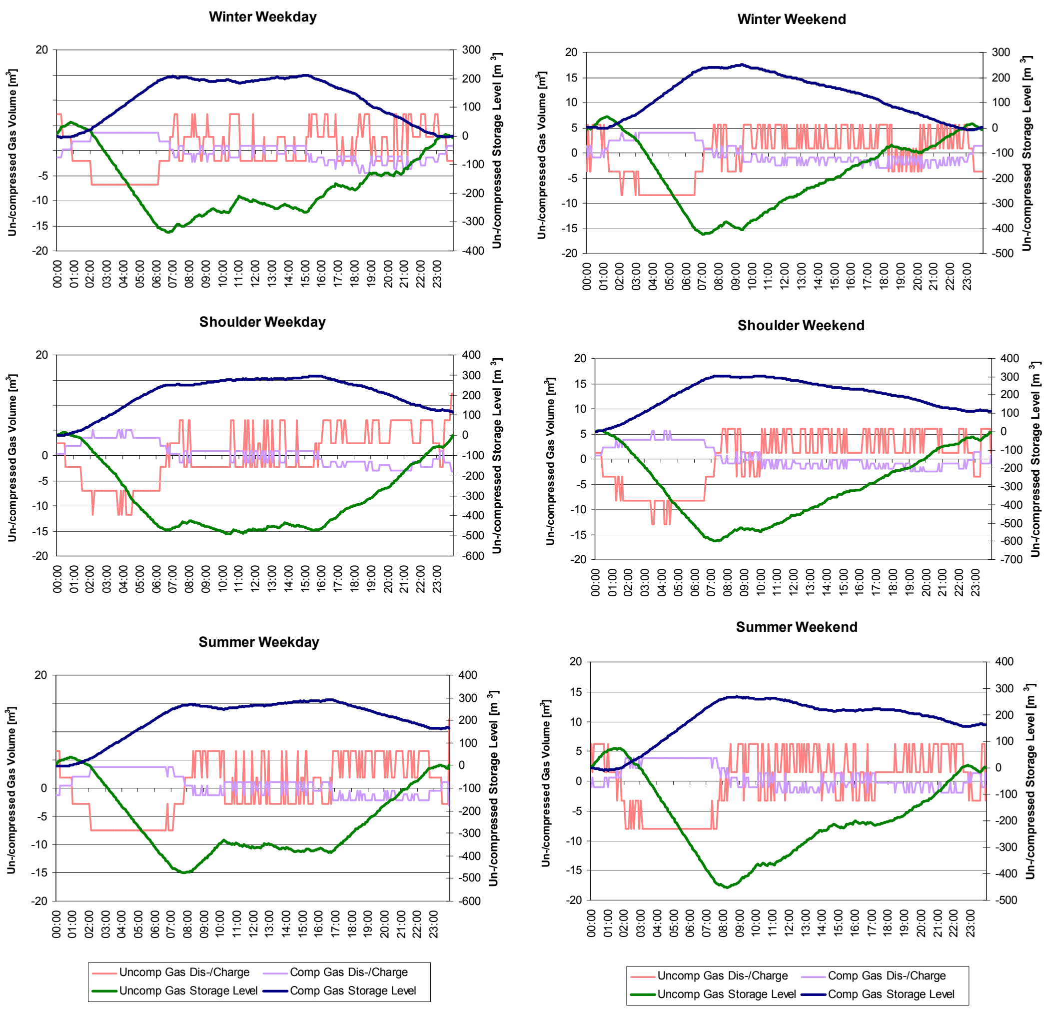

Figure 7-8: Un-/Compressed Storage Levels and Charge/Discharge Cycles.

In addition, Figure 7-8 also depicts the actual amounts of gas that are charged to or discharged from each of the two storages. The line named '*Uncomp Gas Dis-/Charge*' shows the volume of uncompressed gas mix which is charged to or discharged from the uncompressed storage; it equals the production amount minus the amount being compressed, depending on the current fuel compressor power. This means that it becomes positive when the fuel compressor compresses less gas than is produced, in which case this difference is charged to the storage. It becomes negative when the fuel compressor compresses more gas than is produced, in which case this difference is discharged from the storage. The scale again is volumetric with atmospheric pressure.

Simultaneously, the line named '*Comp Gas Dis-/Charge*' shows the charge and discharge cycle for the compressed gas storage. Depending on the generation level of the microturbine, a certain amount of compressed fuel gas is needed. The line shows the difference between the amount of gas compressed by the fuel compressor and the amount needed by the microturbine. This means that it becomes negative when more compressed gas is needed by the microturbine than is provided by the fuel compressor, in which case this additional amount is discharged from the storage. Whereas it becomes positive when the fuel compressor provides more gas than is needed by the turbine, in which case this excess amount is charged to the compressed gas storage.

In general, it can be seen that for the whole period of one day, the absolute storage levels of the uncompressed storage (the lines named '*Uncomp Gas Storage Level*') are balanced to zero. The total fuel compressor power over the whole operation period, i.e. the integral of the compressor power P_{COMP} over the time of the operation period, or the area under the compressor power curve in Figure 7-7, equals the amount of power that the compressor would need to compress the continuously produced amount of gas during equivalent compression (P_{COMP_EQ}), which can be expressed as

$$P_{COMP\_EQ} \cdot \Delta t = \int P_{COMP}(t)dt \qquad (7\text{-}8)$$

Thus the storage levels at the beginning and at the end of the operation period must equal, in this case to zero.

It can be seen that for all seasons, the night periods are the times of discharging uncompressed gas from the storage. This follows from the fact that the demand reaches its lowest levels during the night. As the microturbine is restricted to a minimum power output of half nominal load, the night times are the times of highest fuel compressor power, which can be seen in Figure 7-7. From this follows that during the night the fuel compressor compresses more gas than is being produced, so it discharges the gas from the storage. In comparison to that, during the day and evening peak times, the fuel compressor power is relatively low, as demand peaks and no power is 'left' for the compressor. So during those times, the fuel compressor compresses less gas than is being produced, and as a result the storage is charged with uncompressed gas.

The lowest absolute level of the uncompressed storage is the amount of gas that needs to be provided in order to ensure ongoing operation. It reaches its peak value at a level of between 400-600m^3 for the six cases. Based on a gas production of 3528m^3/day for the discussed base case, which results from the raw feedstock intake rates mentioned in Table 6-I above, this means that between 12-18% of a daily gas production needs to be provided as storage. Both from the point of view of absolute storage level, which influences the storage costs as will be described below, as well as from its relative level, which impacts the operation of the system, this size can be deemed acceptable.

In comparison to that, the compressed storage levels (the lines named '*Comp Gas Storage Level*') show a different pattern. Power supply must match demand, from which follows that for the winter cases, which are the cases with the highest total power demand, the daily gas production equals the amount of gas needed by the microturbine, so all gas compressed will be used by the turbine throughout the day. As night-time power levels are low, the microturbine needs less compressed gas than provided by the compressor, and the storage is charged. Simultaneously, during the times of high turbine generation, the storage is discharged.

However, the compressed storage levels at the beginning and at the end of the operation period are equal for the winter cases only, whilst for the shoulder and summer season a remainder of leftover gas can be seen in Figure 7-8. This follows from the fact that for the shoulder and summer season cases, the total power demand decreases, and thus the power generated by the microturbine also decreases, which results in less gas being needed by the turbine.

For each of the six cases, Table 7-II shows the amount of power generated per day in order to meet demand. It can be seen that whilst the amount of power generated is the same for both winter cases, its respective levels are lower for the shoulder and summer season cases. On the basis of the generated kWh/d, the uncompressed fuel gas volume demanded by the turbine can be calculated, and the respective values are also shown in Table 7-II.

Since the gas production rate remains at a constant value of $3528m^3$/day irrespective of the season, this results in more gas being produced than being needed by the turbine. This '*Excess Gas*' ratio amounts to 9.2-9.5% for the shoulder season cases and 13.6-13.8% for the summer season cases, respectively. Using these amounts of excess gas and the allocation of calendar days to an operation period of a whole calendar year as mentioned in Table 7-I, the annual excess gas production can be calculated as 8.2% of the total gas production.

Table 7-II: Generation Comparison and Excess Gas Calculation.

Case Name	Generation [kWh/d]	Gas Demand [m^3/d]	Excess Gas [m^3/d]	Excess Gas relative [%]
Winter weekday	1624	3528	—	—
Winter weekend	1624	3528	—	—
Shoulder weekday	1470	3192	336	9.5
Shoulder weekend	1475	3203	325	9.2
Summer weekday	1400	3041	487	13.8
Summer weekend	1403	3047	481	13.6

The absolute excess gas amounts mentioned in Table 7-II equal the amount that is left in the compressed gas storage at the end of the operation period as shown in Figure 7-8, however it should be noted that Table 7-II states uncompressed volumes, whilst Figure 7-8 shows compressed volumes.

With regards to the absolute peak levels for the compressed storage, ranges between 200-300m^3 of compressed gas can be seen in Figure 7-8. Based on the daily production of gas, and converting uncompressed into compressed volumes, the storage needs to be sized to around 17-26% of the daily gas production, which again is on an acceptable level.

When running the plant continuously for periods of more than one day, the aforementioned leftovers during shoulder and summer season add up with each day of operation, which results in an increasing storage level for the compressed storage over time. This effect is shown in Figure 7-9, which depicts the absolute levels for both the uncompressed and the compressed gas storage for ongoing generation; the notations *1-5* are for weekdays and *6, 7* for weekend days. The scale again is volumetric at the respective pressure, as detailed for Figure 7-8 above.

The first graph shows a randomly chosen 30-day interval in winter season. It can be seen that the storage levels oscillate around the zero value for each day of operation; this should be expected as the amount of gas produced equals the amount of gas needed for generation. The second chart shows a 30-day interval including the switchover from winter season to shoulder season. Whilst similar oscillations can be found for the winter season part of the graph, the compressed gas storage level begins to continuously increase after the switchover to shoulder season, as excess gas is produced. Similarly, the third graph shows a 30-day interval including the reverse switchover from shoulder season to winter season, and the continuous increase of the storage level during shoulder season discontinues as the winter season begins.

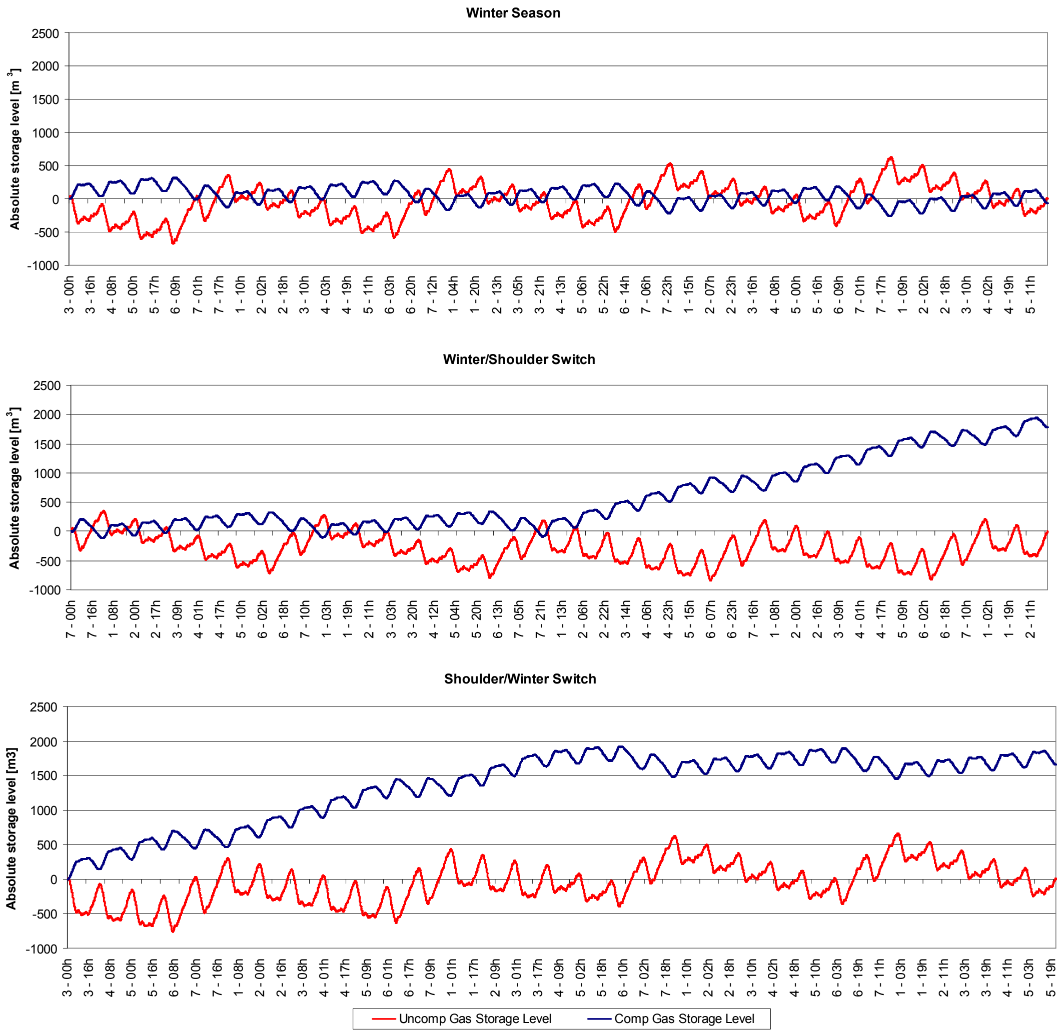

Figure 7-9: Ongoing Generation and Seasonal Switchover.

Ongoing operation would thus result in an ever increasing compressed gas storage level; but since the volume of the compressed gas storage, irrespective of its chosen value, will be finite, this situation needs to be remedied. Three main alternatives exist to handle this situation:

I. The plant design is changed accordingly in order to adjust gas production rates to necessary levels for shoulder and summer season, whilst for the winter season the gas production rate remains at the current level.

II. The plant size is decreased in order to achieve an annual gas production volume of 8.2% below the current level, but this is achieved with a continuous (lower) gas production rate throughout all seasons.

III. The plant design and size remain unaltered and the excess gas is used alternatively.

The first option, to decrease the gas production rate during shoulder and summer season, was found to significantly impact the plant operation. The plant design employs high levels of internal heat stream usage, as described above. The hot producer gas stream for example is used in the microturbine heat exchanger and as a thermal energy source for the digester. If the conversion systems are operated under part-load in order to produce less gas, the streams will cease to provide sufficient heat for the remainder of the plant system. In addition, as has been mentioned in section 4.2 above, the conversion technologies are not suitable to be operated under part-load. Therefore, this option is not viable.

The second option would result in a smaller plant with lower biomass feedstock rates, which then produces 8.2% less gas during one year of operation, however continuously throughout all seasons. The issues of part-load operation of the conversion technologies, and those related to the internal heat usage of the plant as discussed in the previous paragraph, would not occur in this case. However, since a continuous gas production rate throughout the year would be implemented, this would result in producing more gas than needed during summer and shoulder seasons, and less gas than needed during winter season. This however would then result in the necessity of storage for the 'reserve' of gas produced during shoulder and summer season and to be used in winter season.

Given the gas demand volumes for each of the seasons shown in Table 7-II and the allocation of calendar days per year shown in Table 7-I, the adjusted annual gas production rate can be calculated as 1,001,499m^3, which translates into an adjusted daily gas production rate of 2,752m^3. This however means that in order to have a sufficient 'reserve' for the winter season, more than 70,600m^3 of gas would need to be stored. In addition, some of the gas needs to be stored for as long as one year before it would actually be used. It thus becomes apparent that this option is also infeasible.

Therefore, it was decided to follow the third option and to not adjust the gas production rates, but to use this excess gas alternatively. This alternative use could for example be as a source for additional power as a safety buffer for demand increases, or for unplanned quality issues with the fuel gas. Additionally, this energy can be used very productively to pre-treat the plant feedstock: the gasifier feedstock needs to be provided in a certain particle size. A wood chopper, operated in intervals by extra power generated from the excess gas, could hence convert the raw wood, coppice or other feedstock into chips of a fitting size, without incurring extra cost for the operation of the plant.

The energy demand for the chopping of wood into chips suitable for gasification is mentioned in literature as 2-5kWh per tonne of chopped end product [14]. However, the feedstock moisture content influences the necessary energy amount, and it is mentioned that chopping dry wood can require up to 18% more energy than chopping wet wood [14]. In the modelling of this plant, the raw feedstock has been assigned a moisture content of 60%, and therefore resembles fresh wet wood. It was however decided to use the highest of the mentioned values for chopping, i.e. 5kWh/t, in order to achieve a conservative analysis. From this follows that the daily energy demand for wood chopping (E_{CHOP}) can be calculated as

$$E_{CHOP} = 0.1125\,\tfrac{t}{h} \cdot 5\,\tfrac{kWh}{t} \cdot 24\,\tfrac{h}{d} = \underline{\underline{13.5\,\tfrac{kWh}{d}}} \tag{7-9}$$

The theoretical amount of power available from the excess gas (P_{THEO}) can be calculated as 8.2% of the possible shaft power, i.e.

$$\begin{aligned} P_{THEO} &= 0.082 \cdot P_{SHAFT} \\ &= 0.082 \cdot (72.55kW \cdot 24\,\tfrac{h}{d}) = \underline{\underline{142.78\,\tfrac{kWh}{d}}} \end{aligned} \tag{7-10}$$

It can thus be seen that, even when the chopping machinery efficiency is taken into consideration, sufficient power is available for the wood chopping, and the remainder of this theoretical power can still be used for own consumption, safety of supply or demand increases. Finally, should there not be any other productive use of the gas and in order to prevent storage levels exceeding their limits, the excess gas can still be flared off.

7.2.5 Load Profile Fluctuation Analysis

A final investigation needs to analyse the amount and occurrence of fluctuations within the daily load profiles. As described earlier, the plant needs to be flexible enough to accommodate sudden load changes, as there will not be electricity storage available. Therefore, it is essential that the generation always exceeds demand to allow a sufficient buffer for accommodating higher transient loads, i.e. short-time demand increases. The generation calculation algorithms as discussed above are based on the demands of the respective load profiles, however in this section it will be evaluated whether they also provide sufficient excess power to accommodate load fluctuations that occur from one demand data point to another, i.e. on a scale of 5min. This chapter can therefore be seen as a precursor to the transient analysis to be undertaken in chapter 8 which then concludes by analysing transient load fluctuations on a very high resolution.

The load profiles provide average demand data in five-minute intervals through *period integration*, whereas the real demand changes continuously. In order to allow an assessment on whether the profiles can be deemed as a realistic image of the real situation, there are two main characteristics which need to be considered, and which result in diametrical requirements.

On the one hand, real load demand changes continuously, since it is being caused by activation of a number of appliances which do not follow an operation pattern and which are not correlated to each other, as mentioned above. This means that the demand calculated through *period integration* will always be an average of a number of actual demands that occur over the course of the interval, which can be seen in the example in Figure 7-4 above. This effect will occur irrespective of what length was chosen for the measuring interval since numerous actual demand changes can occur even during the course of just one second. By definition, the calculated average demand for each interval will contain lower and higher actual demands. Therefore, there will always be a number of higher actual peaks which are ‘hidden’ by the process of averaging. This is shown to some extent in Figure 7-10 [170], which compares a 1min interval load profile with the results of sampling with a resolution of 5min: it can be seen that the 1min curve shows higher peaks which are hidden in the more averaged 5min data points.

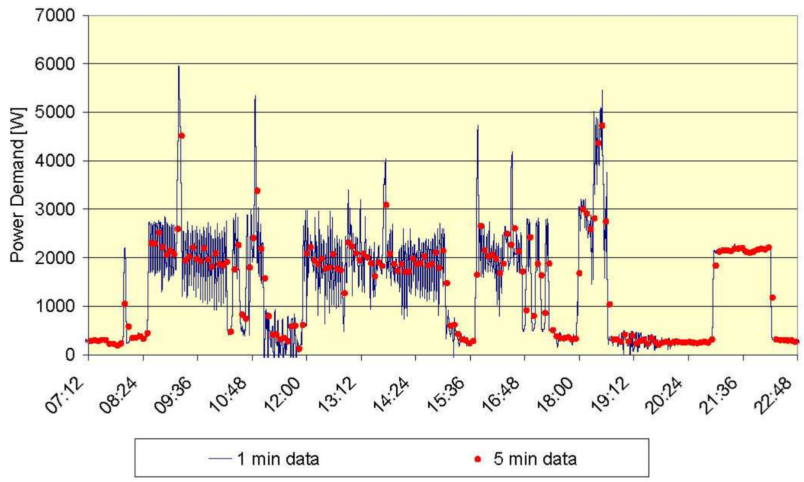

Figure 7-10: Comparison of Load Profiles with 1min and 5min Resolution (Source: [170]).

However, this issue can only be avoided completely by increasing the resolution of the load profiles infinitely, i.e. by choosing infinitely small sampling intervals, in which case the average by definition would equal the actual demand. Since this is not achievable in reality, there will always be hidden peaks, although the difference between the highest hidden peak and the calculated average decreases with decreasing interval lengths.

On the other hand, and this fact remedies the first issue, the load profile becomes flattened and smoothed when it represents a rising number of individual customers as a group, which can be seen in Figure 7-3 above. When merging individual load profiles to a group load profile, individual power spikes interlace and the relative size of the spike, i.e. the difference between the peak demand and the normal demand, decreases. This means that with an increasing group size, the spikes lose their distinction. The important characteristic following from this is that for a constant interval length, the calculated averaged demand value becomes a better approximation for the actual demand with increasing group size, because the fluctuations diminish.

It has been mentioned that for a group of 100 individual customers, a sampling rate of 15min produces realistic and acceptable load profile results with regards to planning and evaluation of generation to satisfy the demand [5]. Therefore, the available data which is based on a group of 69 customers and sampled in a 5min interval can be deemed acceptable, especially since a transient analysis on the basis of very high resolution, i.e. very small sampling intervals, will be undertaken in chapter 8.

With regards to the fluctuations of demand that the plant will have to accommodate when following the operation patterns developed before, it should be remembered that load ramping of a microturbine can be achieved without major impacts on the frequency and voltage of the output power; however the turbine will need around 20-30s to adjust to a new output power, which can be seen in Figure 4-16 above. This implies that the turbine will never be able to immediately follow the load, but that it will need time to adjust to a new power step. Hence, the implemented generation algorithms need to include sufficient buffers to accommodate load changes that occur within the time period of adjusting the microturbine output power. Therefore, the absolute fluctuations of demand from one data point to the next were obtained for each of the six cases, and they are shown in Figure 7-11.

In general, it can be stated that the most significant fluctuations occur during the day-time, whilst during the night only lower levels of demand changes can be seen. This pattern is similar throughout all seasons and does not vary significantly between weekdays and weekends, although the increase of fluctuations is slightly delayed to the later morning hours on weekends.

These findings however correspond to the average activity patterns of inhabited dwellings [170]. During the night, comparably few appliances are switched on or off, so demand is more consistent than during the day-time or evening, where inhabitants use more appliances intermittently.

Discussing the actual size of the fluctuations, it can be seen that for all profiles but the summer weekend profile, peak fluctuations are below 8kW. For the summer weekend case, they reach levels of above 10kW, however only on three (out of a total of 288) occasions. Table 7-III provides the maximum absolute fluctuation for the six cases, as well as its average and standard deviation values.

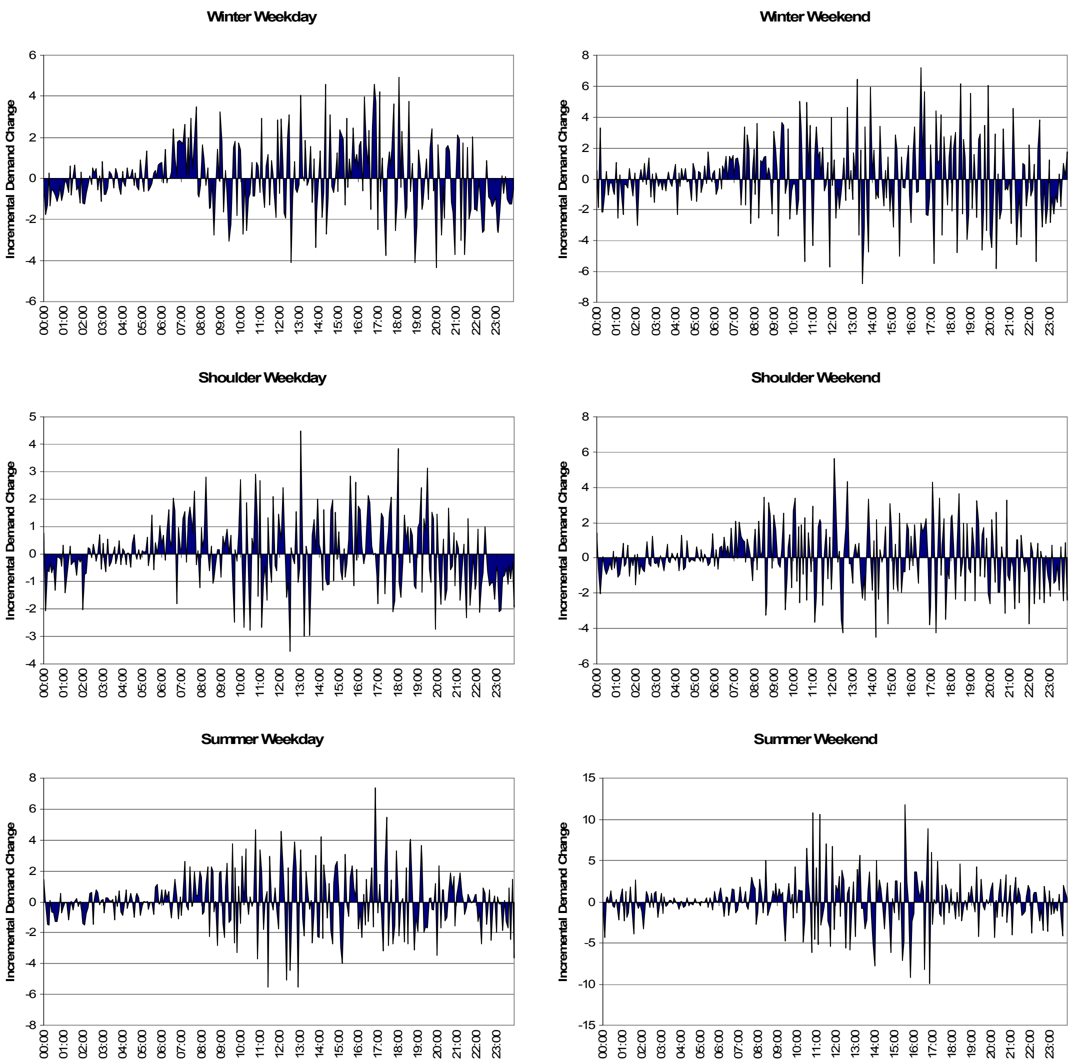

Figure 7-11: Absolute Demand Fluctuations [kW].

Table 7-III: Demand Fluctuation Analysis.

Case Name	Maximum Abs. Fluctuation [kW]	Average Abs. Fluctuation [kW]	Standard Deviation [kW]
Winter weekday	4.92	1.24	1.05
Winter weekend	7.17	1.74	1.51
Shoulder weekday	4.49	0.92	0.79
Shoulder weekend	5.62	1.26	1.08
Summer weekday	7.35	1.32	1.22
Summer weekend	11.77	1.92	2.01

In contrast to demand increases, demand decreases can be treated with ease. In case the demand for power slumps, then more power is available for the fuel compressor, which results in a higher fuel gas throughput. Alternatively, this power can be used by the electric heater should the fuel compressor run on maximum power. Therefore, demand decreases are of low criticality for the system.

The plant however has to accommodate increases in demand by means of the buffers included in the calculation of the generation pattern. The buffers need to be of sufficient size, which means they need to be at least the size of the fluctuations; however, sufficient margins of safety need to be included as well, for example to cater for hidden peaks as discussed above.

The buffers that are available for load fluctuations consist of a variable part and a fixed part. The variable part is the difference between the actual demand and the round-up value to the next multiple of 5kW (P_{DEM_R}), which was used as the basis for calculating the generation pattern, as discussed in section 7.2.3 above. From this follows that the size of this variable buffer will always be below 5kW. Assigning an actual size however is not without risk. Analysing the actual size of the buffer for the six cases reveals levels between nearly 0 and nearly 5, which is the whole possible buffer range. Averages are within a band of 2.3-2.7, however the standard deviation is relatively high with between 1.3-1.6. Therefore, this buffer cannot be allocated a safe value for this analysis and will be excluded, although knowing that additional safety exists, but cannot be guaranteed.

The fixed size buffer is the difference between generation and rounded demand. As mentioned before, it consists of two parts, see eqn. 7-6: the excess power (P_{EXCESS}) and the compressor power (P_{COMP}).

The excess power buffer P_{EXCESS} will always be available for accommodating fluctuations, since it has been implemented for this very reason. Should the fluctuation be below the value of P_{EXCESS}, then the remainder of it will be used up by the plant's power sink, the electric heater, since no power can be stored. The electric heater then converts the power into thermal energy to dry the continuous flow of feedstock particles. Since conventional heaters are very tolerant with regards to the quality of power they receive, and in fact can turn even disharmonic and spiky power into productive heat [5], they are the tool of choice to sink power and will be used for this very purpose in this project. As discussed in the modelling section above, the electric heater can compensate up to 6.25kW of power on a continuous basis, and even higher power levels as long as they occur intermittently.

The second part of the fixed size buffer is the actual compressor power P_{COMP}. Although the fuel compressor is assigned to operate on this power level, in the event of a high-level power spike, automatic control can override this allocation and use part of the fuel compressor power to meet this demand spike.

In order to evaluate whether the buffers can provide sufficient power to accommodate the fluctuations, Figure 7-12 shows the combined compressor power and excess power as well as the fluctuations for each of the six cases.

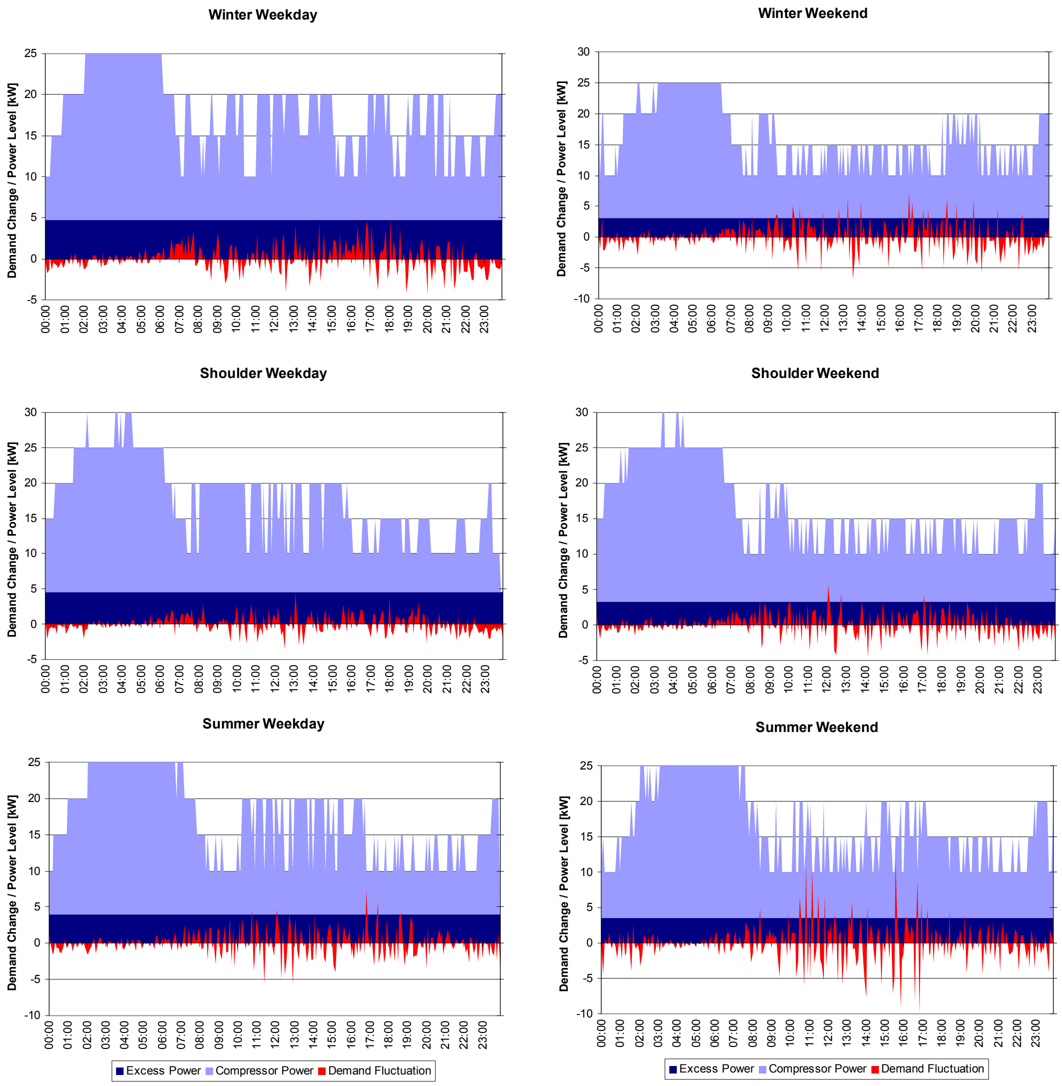

Figure 7-12: Accommodation of Demand Fluctuations.

It can be seen for all cases that the combined power levels of excess power and compressor power significantly exceed the level of fluctuations, and even the highest fluctuations can be accommodated with ease.

In order to evaluate the criticality of the level of fluctuations with regards to the level of the two buffers, a Margin of Safety (*MoS*) can be calculated as

$$MoS = 1 - \frac{P_{FL\_MAX}}{P_{EXCESS} + P_{COMP}} \tag{7-11}$$

with P_{FL_MAX} being the maximum fluctuation for each case, and P_{EXCESS} and P_{COMP} being the respective excess power and compressor power at the time of the maximum fluctuation. Table 7-IV states the different values and the resulting margins of safety.

Table 7-IV: Analysis of Margin of Safety.

Case Name	P_{FL_MAX} **[kW]**	P_{EXCESS} **[kW]**	P_{COMP} **[kW]**	***MoS*** **[%]**
Winter weekday	4.92	4.72	10.28	67.2
Winter weekend	7.17	3.02	6.98	28.3
Shoulder weekday	4.49	4.53	15.47	77.5
Shoulder weekend	5.62	3.26	11.74	62.5
Summer weekday	7.35	4.01	5.99	26.5
Summer weekend	11.77	3.54	11.46	21.5

A margin of safety of zero would imply a very critical case, as the maximum fluctuation in this case would equal the available buffer, which means that a further increase in fluctuations would result in the plant not being able to accommodate the fluctuation. Correspondingly, high margins of safety indicate a low criticality of the case since the plant would be able to accommodate further increases of the fluctuation.

For the six cases in this study, it can be seen that the margin of safety is always significantly above zero, and for half of the cases it is around two thirds or more, which means that even a doubling of the maximum fluctuation could still be accommodated with ease. For the remaining three cases, and especially for the summer weekend case, the margin of safety is lower, but still reaches more than one fifth, which means that a further increase of the maximum fluctuation by 20% could still be accommodated.

Furthermore, it should at this point be mentioned again that with a rising group of dwellings the resulting load profile flattens and smoothens. The original load profiles were obtained from a group of 69 individual customers, however the multiplier used for this study created a group of 120 dwellings. Hence, the flattening effect of increasing the group size from 69 to 120 was not included in the data in order to avoid manipulation of the load profile data. As mentioned above, increasing the number of households in a group has a significant impact on the absolute level of power spikes in a way that the larger the group, the lower the relative value of its power spikes. This however means that for a larger group of dwellings, the level of the highest power spikes will be lower, and for the given group of 120 houses the highest relative peaks will also be below the level of a group of 69 houses, which in turn would mean a further increase in the margins of safety and even lower levels of criticality for those cases.

Even though a more detailed fluctuation analysis on the basis of high-resolution transient load profiles will be undertaken in chapter 8, it can thus already be concluded on the basis of the above findings that the plant is able to accommodate all likely levels of fluctuations with ease.

8 Plant Operation Mode and Transient Analysis

The main aim of the plant is providing ongoing power to its customers through its flexible operation. It was found in chapter 7 that the plant is able to accommodate fluctuations in the customer demand and to match supply and demand. However, up to this point it has not been addressed whether the plant will be operated connected to a grid or in stand-alone, i.e. off-grid, mode. The choice which option to use influences both the economics and the reliability of the plant design. Whilst the economic analysis will be discussed in chapter 9, this chapter will analyse the different possible plant operation modes and their impact on the plant reliability.

A grid connection increases the reliability of the plant as it can absorb disturbances in demand and supply (transients) and can continue to provide power to the customers even during plant outages. However, it comes at a price with regards to investment and compliance. Alternatively, in stand-alone mode the investment into a grid connection can be avoided, but the plant will have to accommodate all occurring transients on its own, and the power supply reliability is limited to the plant reliability. It becomes apparent that in this context a special emphasis needs to be laid on transients that can occur during plant operation, as they can significantly influence the reliability of the plant and of the power supply.

Thus, the first section of this chapter will provide a short general description of transients in power systems, and will evaluate which transients have to be expected for the plant system. In the second part of the chapter it will then be analysed which modes of operation exist for this plant system, and which of those will need to be chosen under given circumstances. A transient analysis of the plant will then conclude this chapter by evaluating whether the plant can accommodate the transients likely to occur at the chosen operation level.

8.1 Description of Transients in Power Systems

Transients in the context of power engineering are defined as sudden disturbances of the steady-state conditions of an electric circuit [173, 174]. During normal steady-state power system operation, generators supply, and customers consume, a certain amount of power, and the grid connects both parties. This means the system is in equilibrium, and generation equals demand. However, when transients occur, this balance between generation and demand is disturbed. Although the period during which transients occur is usually very short when compared to the steady-state period, they can cause high abnormal voltages (over-voltages) or abnormal currents (over-currents) [173, 174]. Causes and effects of transients in power systems have been the subject of extensive and detailed research since they are of high importance for the operation of, and can cause significant harm to, the system. This section can thus by no means provide an exhaustive discussion of the general topic of transients in power systems, which can instead be found in further literature [5, 173-176].

In general, transients can be caused by physical phenomena such as lightning, through abnormal system conditions such as line faults, or during normal operation such as switching of equipment [174, 175]. For example, lightning strikes impose short-term current rises in timescales of less than one to several hundred microseconds; similarly, when a generator or a large load is connected to or disconnected from the grid, transients in the order of micro- to milliseconds are imposed [175].

In addition to these large-scale effects that can impact national power systems, similar effects can occur on a small scale when generation or demand changes significantly from one instant to another, such as when appliances start consuming significant amounts of power or when the output power of the generator changes. Whilst these local transients are normally buffered by the local grid and power system transient analysis is thus mainly focused on the impacts of large transients on transmission and distribution systems, the analysis in this chapter is necessarily limited to the impacts of local transients within the small network of the power plant and its customers. Should this local system be connected to the grid, then local distribution network transients could form another possible source of impacts of the system reliability. Therefore, in the context of this work transients likely to occur can be caused by the following circumstances:

- switching on/off of loads, i.e. significant changes in customer demand;
- switching on/off of generators, i.e. load ramping of the microturbine;
- local line faults and
- grid-imposed transients, such as upstream lightning strikes or auto-reclosure effects.

These four possible causes of transients and their impacts on the system will be discussed in more detail as follows.

8.1.1 Load Switching Transients

When significant changes in the power demand level are triggered by switching on (or off) appliances in a small network, the resulting spike (or slump) in power demand can be defined as a transient which may impact the system reliability.

At each instance of time, the electric power provided by the generator needs to be equal to all the loads in the system, as was described in the simulation chapters above. In such a network system in equilibrium, the generator and the customers can be compared to being directly connected to the same single rotating shaft; the kinetic energy of the shaft rotation is provided by the generator, and it is this kinetic energy that drives the customer appliances. The property that represents the speed of this moving shaft in the power system is the grid frequency, since in reality the grid provides this 'shaft' connection between the generator and the customers. The electrical power that is transmitted through the grid network of this balanced system can thus be defined as work which is provided by the generator shaft, and which is supplied to the customer appliances where it either drives electronic motors or produces heat. When the system is in balance, the frequency is at its set nominal point; and if there is an imbalance between generation and demand, then the frequency will change accordingly.

If, from one instance of time to another, the demand for work is increased, e.g. by starting another large customer appliance, then more kinetic energy of the moving shaft is required by the customers, which means that it is slowed down unless the generator increases its energy output; correspondingly, the grid frequency falls. Similarly, if a large appliance is switched off, then more kinetic energy is provided by the moving shaft than being needed by the appliances, so the shaft is accelerated, and the system frequency rises.

This slowing down or speeding up of the moving shaft in high time resolution is the effect that transients introduce to the power system. As both the generator and the customer appliances cannot respond to a transient in real time due to the kinetic inertia of their (real) rotating shafts, they are restricted to operate at a certain frequency range. It is therefore crucial to accommodate transient demand changes in the system in order to prevent damage to the generator and the customer appliances.

8.1.2 Generator Switching Transients

Whereas the previous section has discussed transients through changes in demand, similar effects also occur when one generator, or in case of this plant the sole generator, is switched on or off, or when it is ramped between two output power steps. Again, the system always needs to be in equilibrium, which means that demand equals supply and the grid frequency remains at its nominal level. In case the generator output power level is modified, the level of kinetic energy it provides to the rotating shaft increases or decreases. If the demand is not modified accordingly, imbalance results and the frequency leaves its nominal level. The moving shaft may either slow down in case the new lower output is insufficient to supply demand, or it may speed up in case the output exceeds the demand. In either case, these changes need to be limited to acceptable thresholds. Hence changing the generator output level can also impose transient effects to the system that need to be accommodated.

8.1.3 Line Faults and Grid-Imposed Transients

Finally, line faults as well as other grid-imposed transients such as lightning or auto-reclosure can also be significant sources of transients for the local system. Line faults can occur irrespective of whether the system is connected to the distribution grid, as they can happen both in the local cabling as well as the upstream distribution grid; grid-imposed transients however will only occur in grid-connected systems.

In either case, when a short circuit or a lightning strike occurs, a very high current and thus a high amount of energy is sent through the network, which means that the equilibrium between the generator and the customers is disturbed [175]. Due to the potential of significant harm to or damage of the equipment caused by these very high levels of current, power systems are normally protected by automatically disconnecting the affected part of the grid through circuit breakers.

However, since transients caused by lightning or short circuits are likely to only occur for very short amounts of time, auto-reclosure methods have been developed to minimise the impact of these faults on the grid operation and reliability. This means that the part of the line where a fault occurs is disconnected from the remaining grid network automatically, but only for a short instance before it is automatically reconnected; should the fault persist at the time of reconnection, the line is disconnected again – this auto-reclosure can be cycled several times before the line remains disconnected in which case a static line fault is expected which needs to be rectified manually [1, 2, 177]. This auto-reclosure limits the period of time during which a faulty part of the network is disconnected from the remaining grid, however through the automatic reconnection more disturbances are sent through the grid [173, 177]. The reconnection is a switching operation which, as was mentioned above, can also impact the balance between generation and demand.

At this point it can be seen that grid-induced transients need to be considered thoroughly due to their potentially very high level. However, these transients can only occur when the local system is connected to the distribution grid. In an operation mode without continuous grid connection, the only likely source of grid-induced transients is a line fault in the local cabling between plant and customers. In this case the whole system needs to be shut down, as this fault evidently will be persistent and will need manual rectification.

8.2 Possible Plant Operation Modes

From the previous section it can be concluded that transients are important issues which need to be accommodated within the system. Whilst they can to some extent be absorbed through the kinetic inertia of the generator, if reaching a high level they can cause harm or damage to the equipment. To prevent this, generators are normally tripped off the network in case the transient would harm them, however this can result in a blackout of the whole system and leave the customers without any power supply. Therefore, transients need to be minimised and strictly controlled, depending on the mode of plant operation.

The possible operation modes depend on whether a grid connection point to the local distribution grid is available, or whether it is feasible to set up such a grid connection point. Depending on the availability of grid-connection, the possible modes of operation can be defined as shown in Figure 8-1.

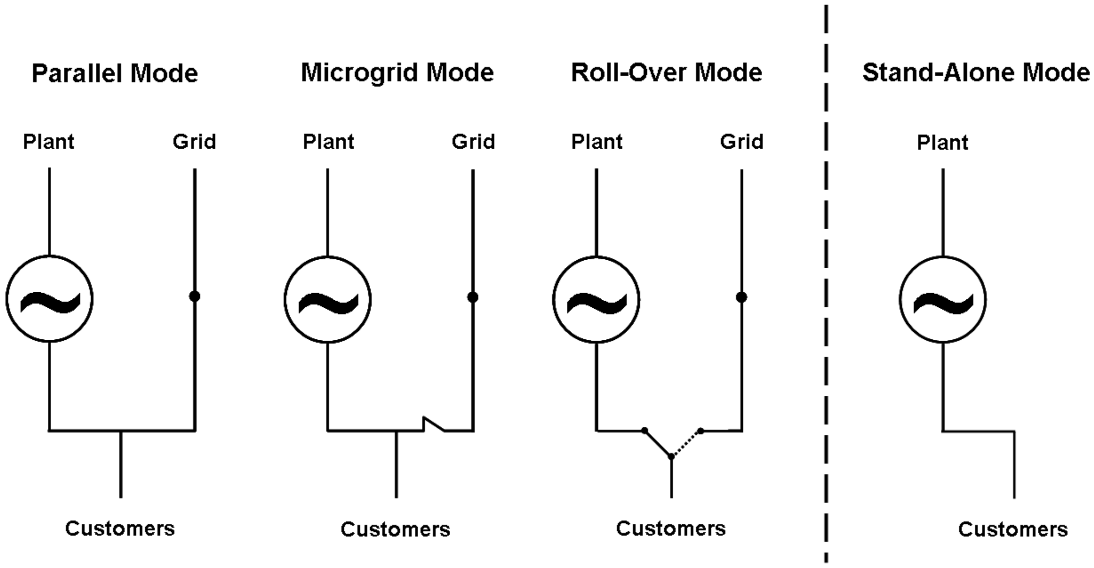

Figure 8-1: Possible Plant Operation Modes.

Of those four possible modes, the first three include a connection to the grid at least for some period of operation, which means they require a grid connection either being available, or being possible to set up. The plant can then be operated *in parallel* with the grid connection, which means that it is synchronous with the grid and connected to the grid through a continuous and uninterruptible connection; it can be operated in *micro-grid mode*, which means that the plant is operated synchronously with the grid, however a circuit-breaker can disconnect the plant and the customers from the grid connection point, in which case it becomes an isolated self-governed micro-grid; or it can be operated in *roll-over mode*, which means that the customers are solely supplied by the plant, and the grid connection is normally deactivated unless the plant has a fault, in which case the plant is tripped off and a grid connection is established by switching over from plant to grid, supplying the customers with grid power.

Should a grid connection be unavailable and infeasible to set up, such as for very remote regions where grid infrastructure would be prohibitively expensive (see the economical impact of distance on grid infrastructure as covered in the economic analysis in chapter 9), then the plant will necessarily be operated in *stand-alone mode*. This means that the plant will be the single and sole power source for the customers, and it means that the local network will be completely isolated from conventional power supply.

The following sections will describe each operation mode in detail, thereafter it will be discussed which mode is the preferred mode of operation for this plant.

8.2.1 Parallel Mode

In parallel mode, the generator is continuously connected to the distribution grid, and is therefore operated synchronously with the grid; the customers are then connected to this network. This mode is equivalent to a conventional grid-connection of the customers and an additional decentralised generator that feeds its power into the local grid. Since the generator is operated synchronously with the grid, it therefore does not provide its power directly to the customers, but it exports it to the grid, which then supplies the customers.

The main advantages of this solution are that the customers can benefit from the high reliability and good power quality of the grid [5]. Compared to power provision from a single power source such as the plant, grid connection can provide power from all other sources that are connected to the grid, which means that grid reliability is significantly higher than the reliability of any single power generator connected to the grid; even for rural grid connections that are likely to be more prone to disruption, reliability can still be an order of magnitude above that of a single generator [5].

Therefore, whilst for robust decentralised power generators such as the plant in this project, reliability levels up to 98.5% can be achieved, grid reliability on average is around 99.8% [5]. This means that for one year of operation, likely outage times of the generator due to planned and unplanned maintenance would amount to around 130hrs, compared to only 14hrs of outage time of a grid connection. Since in parallel mode the customers are continuously connected to the grid, they can benefit from this higher grid reliability even in case of a plant outage.

The second benefit to the customers is the high quality of grid power. Since the grid interconnects a large number of generators and customers, it can normally accommodate all local transients with ease by automatically adjusting its power flow; in fact, as mentioned in chapter 1, it was designed for this very reason [5]. Therefore, transient accommodation in parallel mode is of low criticality.

However, operating in parallel mode requires the generator to fulfil grid-compliance standards and can therefore be challenging with regards to regulation, controls and protection [5, 177, 178]. Connection to the grid will also be likely to incur connection and operation charges from the local grid owner; whether these are regulated or de-regulated depends on the country, however it is very likely that these charges are prohibitive for micro-scale plants, especially those with very fluctuating output [5, 177]. Connection to the grid may, depending on the regulatory framework, also mean that the power produced by the generator needs to be sold to the grid, and that the customer's demand will be provided by (and sold through) the grid, so there may be a significant amount of administration, accounting and paperwork involved [177]. Apart from these regulatory issues, the generator needs to have advanced control and protection in order to be allowed to operate synchronously with the grid. Grid protection standards for example require that grid-connected generators trip off when an outage occurs in order to protect the grid from the generator, and vice versa [5, 178]. This requires a close monitoring of both the grid and the generator, and can be costly. Since heavy grid-imposed transients such as from lightning strikes or line faults can trigger this switching off of the generator even though they are just temporary, the result is that grid-imposed outage times of the generator can hamper its own reliability [5, 177].

This in fact means that in parallel mode operation the generator will not be allowed to operate in case of a persistent line fault, which compromises the intention of providing power locally to replace or support a grid connection that is prone to disruption. This, together with the substantial costs and burdens of regulation, controls and protection of operating the generator synchronously with the grid, make parallel mode an unlikely option for the intentions of this project.

8.2.2 Micro-Grid Mode

The micro-grid operation mode is an adjustment of, but similar to, parallel mode. Under normal circumstances, the generator is directly connected to the local grid and is operated synchronously with the grid, and the customers are provided with grid power. However, the connection between the generator and the grid is interruptible, so during a grid fault the connection of generator and customers to the grid is disabled through the circuit breaker shown in Figure 8-1. In comparison to parallel mode, where during a grid fault the generator is tripped off and the customers will not be provided with power, in micro-grid mode the generator continues to supply power to the customers. In this case, the generator and the customers form an isolated power island, or micro-grid; this power island is disconnected (isolated) from the faulty grid, but is still active (energised) through the power provided by the generator [2, 179]. Once the grid fault is rectified, the circuit breaker can be closed and the micro-grid can be connected back to the main grid. In conclusion, micro-grid operation mode combines parallel mode (as long as the grid is active) and stand-alone mode (during a grid fault).

This option therefore combines the benefits of parallel mode with the possibility of operating the generator as a stand-alone option in case of a faulty grid. This means that the customers can benefit from high grid reliability and power quality, but the generator availability is not limited to the grid availability, which means that it can continue to supply power to the customers without being tripped off. However, this option also combines the disadvantages of both options; the generator needs to fulfil all grid-compliance requirements that were discussed in section 8.2.1 since under normal circumstances it will be operated synchronously. In addition, during a fault in the grid, the generator needs to be able to provide power to the customers in stand-alone mode, which means that it will have to be able to accommodate all local transients. Finally, once the grid fault is rectified and the micro-grid consisting of generator and customers is to be reconnected to the main grid, this reconnection needs to be arranged at grid-compliance level; should the micro-grid not be fully synchronised with the main grid, reconnection can severely damage the generator [2, 179]. It should at this point also be reminded that additional transients can be imposed when connecting or disconnecting the micro-grid from the main grid, since these events are switching processes as mentioned in section 8.1.3.

As a result, the costliness and the administrative requirements of the parallel mode again make it highly questionable whether the micro-grid mode is a feasible solution for the plant design of this project, and this is further amplified by the reconnection issues. Micro-grid mode should, however, be preferred over parallel mode in order to support a grid connection that is prone to disruption, as it maintains power supply in case of a line fault.

8.2.3 Roll-Over Mode

In comparison to parallel and micro-grid mode, in roll-over mode the generator and the main grid are never directly connected to each other, and at any single time only one of the two is ever connected to the customers to supply them with power [5]. Under normal circumstances, the connection to the main grid is disconnected and the generator provides the customers with power independent from the grid. However, in case the generator is faulty, the customers can be switched over to grid connection and can be supplied with grid power. Roll-over mode therefore resembles stand-alone mode during normal operation and grid connection during generator outages, and the customers can be 'rolled over' from one of the two sources to the other; this is shown in Figure 8-1 with the switch between customers, generator and grid.

The main advantage of this operation mode is that no grid-compliance requirements will be imposed since the generator will at no time be grid-connected. This means that both control and protection of the generator are much simpler when compared to synchronised operation; in addition, grid regulation will not be applicable, which means that the above-mentioned charges and administrative burden will be avoided. Furthermore, grid faults and grid-imposed transients will not impact the local generator or the customers, since under normal circumstances they will be disconnected from the grid. This mode therefore significantly eases the operation especially of small and micro-scale plants. Due to the possibility of switching over the customers from the generator to the grid in case of a generator fault, the grid can however provide additional reliability to the power supply. This is an important factor since the availability of local generators will normally be below that of the grid [5], as was mentioned in section 8.2.1.

However, since the switch-over between generator-supplied and grid-supplied power will not happen instantaneously, the customers will have to endure a short period during which they will not be connected to either source, even though this period should be very short in case an automatic sensor is used [5]. In addition, it will not be possible to use the grid to accommodate local transients and to benefit from its high power quality, since there is no continuous grid connection. The generator therefore needs to ensure sufficient power quality and it needs to be able to accommodate all local transients. Finally, since the local grid connection will only be used in case the generator is switched off, it means that the grid connection will be severely underutilised, as those outage times are relatively short; based on the reliability levels mentioned in section 8.2.1, the grid would provide power for only 130hrs per year of operation.

It can thus be concluded that this operation mode makes the best use of an existing grid infrastructure for purposes of reliability, whilst at the same time ensuring ease of operation for the generator. Especially for small or micro-scale plants it will be the only realistic option when faced with the alternative of significant costs and administrative burden of grid-connection. Since the plant design and simulation studies were already focused on flexibility of operation in order to closely match supply and demand, roll-over mode without doubt is the preferred mode of operation for this plant. However, in case there is no access to a grid connection at all, the only remaining mode of operation will be continuous stand-alone operation.

8.2.4 Stand-Alone Mode

Should no grid connection point be available at all, or should the set-up of a grid connection be prohibitively expensive, then the only possible alternative is stand-alone operation of the plant. In this case the microturbine will be the sole generator and the only source of power for the customers. From this follows that there will be no grid interaction at all, so the customers and the generator form a grid-independent power network, as shown in Figure 8-1.

In stand-alone mode, the generator is directly connected to the customers and supplies them with power, so grid-compliance regulation does not apply. This means that the costly technical and regulatory requirements of grid-connection can be avoided, as this set up is similar to the roll-over mode discussed above. However, the disadvantage of stand-alone mode is that there will be no possibility of switching to a grid connection should the plant be at fault, which means that the reliability of providing power to the customers will be limited to the plant availability. Once an outage of the plant occurs, the power supply to the customers will cease until the fault is rectified. Additionally, similar to the roll-over mode the generator operated in stand-alone mode will have to accommodate all transients caused by the customers, and maintain sufficient power quality.

In conclusion, this mode of operation provides fewer benefits than roll-over mode as there is no increased reliability of power supply through the option of switching to grid power. However, since this mode would be limited to areas where no other means of power provision is available to the customers, it would still be a significant improvement to have the plant as a stand-alone generator and source of power than to not have a power source at all. And since one of the objectives of the plant design was enabling long operation cycles and low maintenance, outage times of the plant will be relatively low; see also section 8.2.1 above.

8.2.5 Choice of Operation Mode

Having covered each mode of operation and its respective advantages and disadvantages in the previous sections, it now needs to be decided which mode to apply to the plant design of this project. With regards to the best cost/benefit ratio, it was mentioned elsewhere that conditions likely to favour stand-alone or roll-over operation of small power systems are [2, 7, 177]

- requiring comparably low amounts of power;
- being remotely located from the grid connection point;
- being connected to a power line that is prone to disruption;
- having costly and regulation-intensive grid-connection requirements;
- having reliable local generation options available and
- being able to locally source sufficient feedstock for ongoing operation.

The opposite of those criteria applies to a favourable environment for grid-connected generation [2, 177].

Especially for remotely located micro-scale plants such as in this study it thus becomes apparent that there is a strong tendency towards roll-over mode in case of a grid connection being available, and stand-alone mode in case of a grid connection being infeasible.

Therefore, it can be concluded that those two operation modes will likely be applicable for the plant. From this follows that a transient analysis needs to be undertaken in order to evaluate whether the plant system is able to accommodate all transients that can occur. This analysis concludes this chapter and will be covered in the following section.

8.3 Transient Analysis

It has been decided in the previous section that the system will be operated without grid connection for most (under roll-over mode) or all of the time (under stand-alone mode). Since the simulation studies in section 7.2 above have already included an analysis of the likely fluctuations of demand from one data point to another on the basis of five-minute intervals, it needs to be concluded in this section whether the plant can also accommodate the transient fluctuations of the system.

Therefore, the first part of this section will evaluate possible transient sources under these modes of operation; thereafter it will be analysed what level of transients is likely to occur, which will be done on the basis of high-resolution transient load profiles obtained through simulation; finally, it can then be concluded whether these transient levels can be accommodated by the plant system.

8.3.1 Transient Source Evaluation

The local system within which transients can occur consists of the generator (i.e. the microturbine); local cabling between the generator and the local customers; the system loads (i.e. the customers); and the grid connection point (in roll-over mode only). Possible transients in this system may result from three different sources (see also section 8.1 above):

I. Line faults in the local cabling;

II. Transients in generation through power ramping of the microturbine between different output power load steps; and

III. Transients in demand through load changes of customers.

Since the system will not normally be connected to the distribution grid, additional grid-imposed transients are not likely to occur and can therefore be excluded.

Line faults such as local short circuits or lightning strikes in the local cabling may provide the highest transient levels of current, so protection of the customers and the generator against local line faults will be necessary. This however should normally be the case with all generators due to their built-in protection: in case a local line fault occurs between the microturbine and the customers, the over-current will trigger the generator protection equipment, which will disconnect the generator from the network and shut it down automatically [5, 177]. On the customer side of the network, fuses will normally be used to protect the customer from over-currents, and they will be operated in case of a line fault [1]. From the moment the generator is disconnected and the fuses are operated, the whole system will become inactive (not energised) so that the customers will not be harmed. However, this also means that the customers will not be provided with power until the line fault is rectified, the fuses replaced and the generator restarted and reconnected. This is a necessary and reasonable restriction that is also in place for all other grid-connected customers. In addition, it has been reported that most outages that are likely to happen in the distribution system are not caused at the street level but in the regional overhead lines of the distribution grid [2], so local line faults due to short circuits or lightning strike are somewhat less likely to happen than line faults of regional distribution grids.

Transients in generation through power ramping of the microturbine will occur frequently since the microturbine adjusts to the fluctuations in demand by changing its output power between half and full nominal load, as was discussed in the simulation section 7.2. When the microturbine changes its output between two load steps, it will create a transient as described in section 8.1.2; however, as discussed in section 4.3.2.1 above, transients of microturbine power ramping were studied extensively [117, 118, 132] and it was found that the ramping of the turbine is smooth and does not produce significant transients that could impact the system stability.

Finally, *transients in demand* are also likely to occur, since the customer demand fluctuates heavily over the course of the day, as was explained in section 7.1 above. These transients happen whenever customer appliances are switched on or off and thus occur constantly, and they cannot be accommodated directly by changing the microturbine output since this process has a time lag of several seconds. These load transients thus need to be accommodated within the system.

This however is the main reason for implementing the system power sinks, i.e. the electric heater and the variable power fuel compressor. The amount of power provided by the turbine therefore needs to be sufficient to supply the peak transient customer demands, with the remainder of the power being 'used up' by either the fuel compressor or the electric heater. Since these transients occur instantaneously, the amount of power available for the fuel compressor and the electric heater will fluctuate simultaneously. However, the electric heater can be operated on fluctuating power levels, disharmonics and power spikes with ease [5]. From this follows that as long as the microturbine output is sufficiently large to cover these transient power demand peaks, the system will be able to accommodate the transients through a preset control that automatically adjusts the electric heater and fuel compressor power levels to the remaining available power.

It hence has to be evaluated whether the microturbine power output sufficiently exceeds the transient customer peaks, in which case the system will be feasible to operate in roll-over or stand-alone mode. In the following section, this evaluation will be undertaken by analysing transient customer load profiles and thus the likely levels of transient customer demand peaks, which can then be compared to the microturbine output power.

8.3.2 Transient Load Profile Analysis

The following transient analysis will be performed on the basis of simulated transient load profiles obtained from literature [180]. As mentioned in section 7.1 above, there are two main ways of obtaining load profiles, which are measuring the actual demand patterns of a customer group, or simulating the demand patterns on the basis of expected behavioural patterns of the customer group. Whilst the load profiles used in chapter 7 were obtained through measuring a group of individual residential customers, the profiles to be used in this section were obtained on the basis of modelling.

The profiles are based on modelling the behaviour of a group of 160 households, representing the average size of a substation in the UK [180]. It was already mentioned above that the main power consumers in residential customer profiles are electrical appliances. Following from this, the profiles are based on typical sets of appliances and the consumption patterns of each appliance over the course of the day. By including the interlacing effect that occurs due to different customers having different usage patterns (see also Figure 7-3), the individual load profiles can then be assembled into a group profile representing the substation transient demand level. This method calculated demands in one-second intervals and then averaged the demand to five-second intervals which were recorded as the raw data [180].

In a final step, the raw data that represents the transient demand of a group of 160 households was then adjusted to the group size of 120 houses which was the size for the simulation cases in chapter 7 above. This obtained data set will be used to evaluate whether the plant operation patterns can accommodate the likely transients in the analysis of the following section.

Since it was found in section 7.2.5 above that the summer cases are those with the highest level of criticality as demand and generation are at their lowest level and changes in demand are thus at their relatively highest level, it was chosen to use the transient load profiles for a summer weekend case to undertake the transient analysis.

8.3.3 Transient Accommodation Analysis and Conclusions

On the basis of the above-mentioned five-second average demand data, it was possible to calculate the change of demand, i.e. the transient demand fluctuation, by obtaining the difference between two consecutive five-second intervals. This resulting transient change of demand is shown in Figure 8-2 in chronological order.

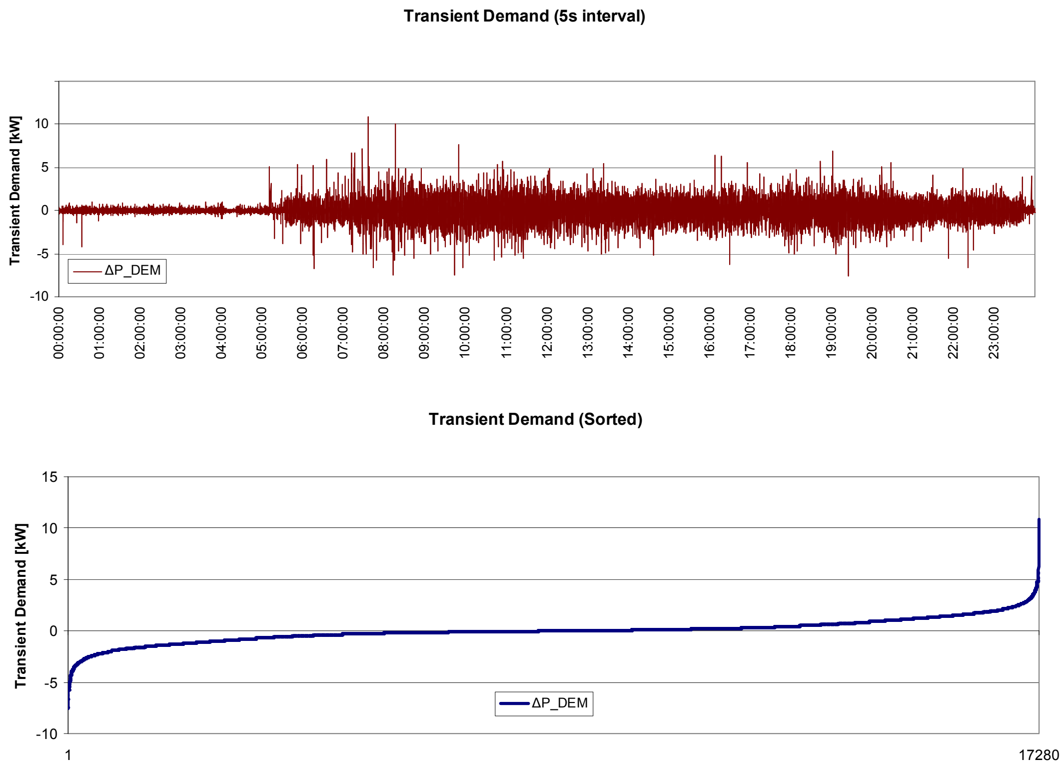

Figure 8-2: Transient Change of Demand (Chronologically and Sorted).

Although the transient fluctuations used in Figure 7-11 were based on a different household group and on measurements of five-minute intervals, they are very similar to the five-second interval transient fluctuations shown in Figure 8-2. As the two data sources are unrelated, it also shows the validity of both data sets.

Demand fluctuates from one instance of time to the next as customers in the group switch on or off their appliances, but the overall transient change is within a relatively narrow range. This range is shown strikingly when sorting the transient changes by their actual size, which is also shown in Figure 8-2. It can be seen that whilst the maximum transients reach -7.5kW and +10.9kW respectively, very few transients are outside the range of ±5kW, and more than 95% and thus the vast majority of transients is within a range of only ±2.5kW.

The transients are significantly more distinct during the daytime, as power demand during the night is substantially lower and thus changes in the demand are likewise lower. During both daytime and night, the transients are within a range of around 10% of the average absolute power demand at that period of time; this means that during daytime the demand fluctuates around ±5kW whilst the average demand of the group is around 50kW, and similarly during the night the demand fluctuates around ±1-2kW whilst the average demand is around 20kW.

To evaluate whether the plant operation patterns can accommodate the shown levels of fluctuation, it is necessary to remember how the plant is supposed to handle transients during operation. As mentioned in detail in section 7.2.5 above, the plant is run flexibly to enable transient demand changes to be accommodated; the microturbine is operated at a power level that exceeds the expected demand, and the difference between those two amounts of power can be used to accommodate transients. If not all power is used for transients, it will become either *Excess Power*, which is used by the electric heater, or compressor power for the flexibly operated fuel gas compressor. Both of those values can therefore be used to accommodate transients in demand, and in order to understand whether the plant operation pattern can accommodate all likely transients, it needs to be evaluated whether the sum of those two buffers is below the transient. Both buffer values vary considerably during the day, which was shown in Figure 7-12 above, and since the occurrence of transients is also dependent on the time of day, it needs to be evaluated whether sufficient power is available whenever transients occur.

Therefore, Figure 8-3 shows both the five-second interval transients and the respective levels of excess power and compressor power for the whole one-day period.

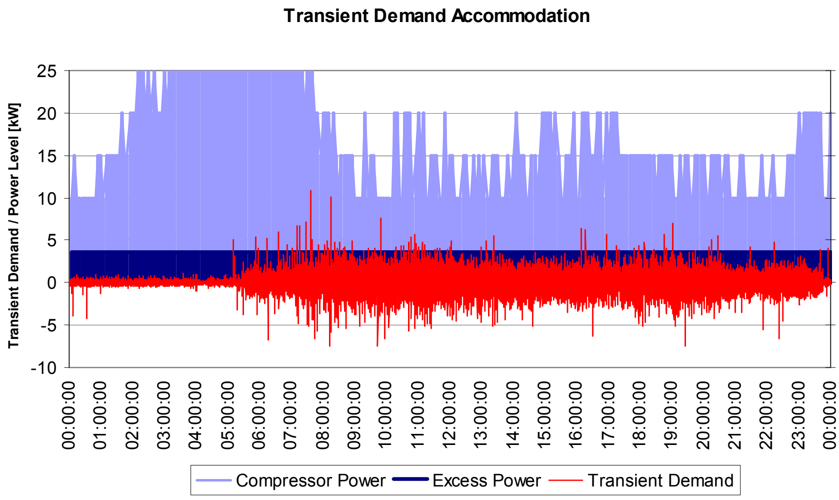

Figure 8-3: Transient Accommodation Analysis.

As was discussed in section 7.2.5, negative transients or power slumps are of low criticality for this analysis; should the power demand decrease substantially, then either the compressor power level or the excess power level would increase, which means that the plant would use more power in the compressor or the electric heater. As this effect was intentional, and since the electric heater can also use very high levels of power as long as they are intermittent, which was described in section 6.1.4, the plant will be able to accommodate power slumps with ease.

With regards to positive transients or power spikes, it can be seen in Figure 8-3 that the level of transients is always conveniently below the level of the combined excess and compressor power, which means that the transients can be accommodated at all times without significantly impacting the plant operation. It can also be seen that the majority of transients do not even exceed the level of excess power, which means that their only impact to the plant is that the amount of excess power is reduced accordingly, which means that less power is diverted to the electric heater. Since the system of excess power and the electric heater were implemented for this exact purpose, the result also shows that a fitting level was chosen for the excess power, and that the plant operation patterns are thus optimised. Those transients that exceed the excess power level and reach into the compressor power level as shown in Figure 8-3 do require the fuel compressor power level to be adjusted automatically. This means that a certain amount of power originally designated to the compressor will be ‘used up’ by the transients, thus the compressor will receive less power than planned. However, since those transients only occur during a very short period of time when compared to the whole period of operation of the compressor, they will not influence the overall productivity of the compressor operation.

Finally, in order to evaluate the criticality of the system, calculating the margin of safety using eqn. 7-11 results a value of 43.5%, which indicates that the actual criticality of the case is below the value calculated on the basis of five-minute intervals as mentioned in Table 7-IV.

This however was to be expected; it was mentioned above that the data used for the initial five-minute interval fluctuation analysis in section 7.2.5 was based on a group of 69 households, whilst the plant design is intended for a group of 120 households. So a relatively lower level of transients and thus a lower criticality level were to be expected when using data that fits the right group size, such as the five-second transient data in this analysis.

In conclusion, it can be stated that in both the initial fluctuation analysis that uses five-minute interval data, as well as in the current transient analysis that uses high resolution five-second interval data, the plant has shown a very high level of robustness and can without implications accommodate all likely levels of transients. The plant has thus proven that it can be operated feasibly in both roll-over and stand-alone mode, and that it can thus be deployed both off-grid and to support a remote grid connection.

9 Economic, Sensitivity and Efficiency Analysis

In the previous chapters, the system design was developed and modelled and its operational feasibility was evaluated in simulations. In order to complete an overall understanding of the implications of such a plant, an economic analysis is another necessity and will conclude this project.

Therefore, this chapter will perform an economic analysis of the plant design to understand its cost implications on the principles of general power systems economics. Using quoted and published costs and expected revenues, it will be evaluated whether the plant can be operated profitably or whether, and to what extent, losses would occur. As part of the analysis, this chapter will also look into the topic of costs and benefits that cannot easily be expressed through monetary values, and how to include those factors in a decision-making process. The results of these analyses will then be compared to the cost implications of a conventional grid connection.

In order to accommodate price and revenue uncertainties, a sensitivity analysis will then evaluate how the results change when some of the parameters are varied.

Finally, the efficiency of operating the plant will be calculated and compared to the efficiency of providing conventional grid power, to compare the performance of the plant to its main alternative.

9.1 Economic Analysis

In order to analyse the economic impacts of investing in any power system to change a current situation, two main questions normally arise [5, 181]. The first question is whether to invest in a system at all. This means ‘doing nothing’ normally is a viable option and should be evaluated; however, it is not always possible to do nothing, for example when customers currently have no access to power at all and/or when utilities are required to provide customers with a power source. In those cases, once it is agreed that remaining inactive is not an option, what follows is normally a question of choosing one of several alternatives. In this case, an economic analysis can be used to evaluate whether an alternative can provide economic incentives for an investor, and furthermore whether it should be preferred over other alternatives.

To understand the cost implications of a power system, it is necessary to calculate what investment a given system would have, and how much it could earn over its lifetime. It then needs to be evaluated whether this system can be provided profitably or whether there are other and better alternatives. As mentioned above, this means that it may also be possible to conclude that neither alternative provides a decent investment opportunity. In this case, none of the alternatives should be undertaken unless it is required, in which case the alternative with the lowest loss should be chosen. Since the plant in this project is designed to provide a small group of customers with power, it means that there are two main alternatives: either the customers are already connected to a grid connection, or they are not currently connected to any power source. In the former case, it could be evaluated whether the plant provides enough incentives to replace or support the grid connection; this might become even more important in case of a connection prone to disruption, or in case of a connection in need of upgrading and thus further investment. In case no grid connection is available, it could be evaluated whether the plant provides a better alternative than setting up a new grid connection.

To evaluate whether an alternative provides a suitable incentive for an investment, it needs to be understood what the cost implications of such a system are. This means that both investments and returns need to be analysed for the duration (or lifetime) of the project. By calculating the investments that arise during the lifetime of the project, and by calculating what revenues the system will earn through selling its product (i.e. its power), it can be evaluated whether a positive or negative overall return can be achieved.

9.1.1 Handling Future Investments and Revenues

When analysing a power system, it becomes apparent that both investment and revenue streams will not only occur at one point of time (i.e. at the time of analysis), but that instead they will occur regularly. For example, revenues will be earned on an ongoing monthly or annual basis, and investments into the plant will be undertaken both at the beginning (for construction and set up of the plant) and throughout its life (such as for maintenance and replacement parts). Therefore, a power system analysis will need to calculate the costs and revenues of not only one point in time, but during a period that covers the whole lifetime of the plant.

It is general practice for power system analysis to employ periods of around 20 years in order to evaluate the plant economics over the plant lifetime [5, 14, 181]. Most power system equipment is built for long lifetime periods of 20 years or more, thus equally long periods are commonly used to amortise or repay the investment in such a system. However, uncertainties of forecasting evidently increase for ever longer periods, so analyses over a significantly longer period become more and more questionable [181]. Therefore, the following analysis will also be performed over a 20 year period.

Using such a lifetime period however has implications for the calculations of the economic analysis, as the value of future investments and earnings needs to be calculated. Those investment and return streams which happen in the future need to be corrected to represent a 'present money value' for the day of the analysis. This simply follows from the fact that any investor, if given the opportunity to earn £1 today or £1 next year, would (and should) prefer to earn it today and not next year; similarly, an expenditure of £1 today will be less favourable than an expenditure of £1 a year from now. Thus future earnings are worth less than present earnings, and similarly future investments are less punitive than present investments.

This lower current value of future money is based on several factors [5, 14, 181]: if an investor can earn £1 today, s/he can invest it for the duration of one year and can earn interest on it, if only through the standard interest rate. So if the investor invests wisely, s/he should be able to obtain more than £1 in a year's time, which means that a discount value to correct future money into current value needs to contain a value representing the interest that can be earned on that money.

Additionally, the discount value should also reflect the risk of that particular investment, thus it should normally be above the normal base interest rates of risk free investments. Since interest and risk are interrelated, high interest represents high risk; therefore, investment in a power plant which at least to some extent has unknown costs and revenues should earn more interest than any risk free investment, and thus the discount value normally consists of the base rate interest and an adequate risk premium.

Furthermore, the discount value normally includes some margin to represent planning uncertainties and unavoidable planning errors, thus it biases the decision for or against an investment by making it more reluctant against spending money in the present to receive uncertain revenues in the future.

Finally, due to normal inflation £1 next year will buy less than it does today, which means that £1 next year is worth less than £1 in present value. However, it should be noted that inflation applies to virtually all cost and revenue streams in an economic analysis, so most discount values used for planning calculations are exclusive of inflationary effects [5], which was also applied for this analysis.

In either case, those basics of economic analysis mean that discount values need to be used to transform future investment and earning streams into current values. Discounting an amount of money in the future (A_f) into a current value (A_c) is done by using

$$A_c = \frac{A_f}{(1+r)^n} \tag{9-1}$$

with r being the annual discount value or rate (in %) and n being the number of years between the point in the future and the current date. The choice of a discount value can heavily influence the results of an economic analysis, therefore it needs to be evaluated which discount value to use.

For the purpose of power system analysis, annual discount values between 5-10% are commonly used and mentioned as reasonably representing both the risk of an investment into a power system, and the expected return on investment [5, 110, 141, 182, 183].

Figure 9-1 shows the effect of adjusting £1 with discount values of 5%, 8% and 10% over the course of 20 years, and a value of 8% has been chosen for the analysis of this chapter. However, as part of the sensitivity analysis below, further variations of this parameter will also be evaluated.

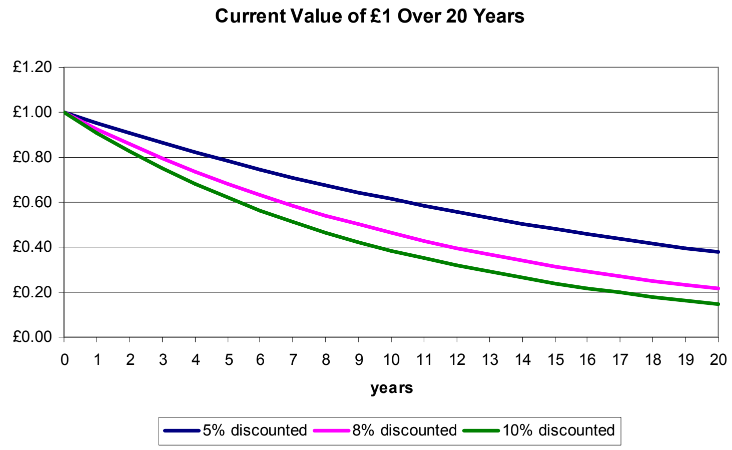

Figure 9-1: Current Value of Future Money.

In order to calculate the overall return of a power system, all investment and earning streams will need to be evaluated. Future investment and earning streams can then be discounted to obtain a net present value of the system, which if positive provides the cumulated net present return and if negative provides the cumulated net present loss.

9.1.2 Investments

Investments into a power system can be classified as either fixed or variable costs, the former being irrespective of the actual operation level of the plant and the latter occurring proportionately to the plant operation level. For power system economics, three main cost categories are generally used, which are the capital costs of investment and setup of the system, the ongoing operation and maintenance costs, and the cost of providing fuel for the plant [5, 6, 181, 182]. Of those costs, capital costs are fixed costs since they occur at the beginning of the plant's lifetime and before the plant has produced a single unit of power. Operation and maintenance costs include costs for staffing and administration, maintenance labour and spare parts as well as consumables such as lubricants or power demand; although some maintenance will occur irrespective of the plant output, these costs are normally dependent on the level of operation of the plant and are thus counted towards variable costs. However, especially for smaller systems it was found that operation and maintenance costs are difficult to account for and are comparably low when compared to the capital costs [2, 182]. They can therefore also be included as a percentage of the capital cost of the plant and be deemed to occur annually or in similar intervals. Finally, fuel costs include the cost of fuel provision to the plant, i.e. they consist of the fuel cost itself, and of the transport and storage costs. They are intrinsically variable costs since they depend on the amount of fuel used, which itself depends on the amount of power generated.

9.1.2.1 Capital Costs

The capital costs of this power system consist of the investment cost of buying and setting up its main components, as well as the erection of wood chip storage (see section 9.1.2.3.1 below) and the installation of auxiliary cabling, piping and buildings. Based on published and/or quoted prices [14, 60, 110, 122, 135, 184-186] for the main units (gasifier, anaerobic digester, microturbine, gas storage system and wood chip storage), and including a conservatively chosen 20% buffer to account for the auxiliary costs and to cater for price uncertainties and possible issues during construction, the total capital costs of this plant are shown in Table 9-I and conclude to a total one-off investment of around £475,950 for the base case plant size used in this project. The prices, where indicated, were converted into current (2010) Pound Sterling values by correcting them with the average quarterly producer price increase rates [187] and by using average currency exchange rates [188].

Table 9-I: Plant Capital Costs.

Unit Description	Investment [£ 2010]
Gasifier system (60kg/hr wood input)[1]	91,750
Anaerobic digester (300m^3, incl. digestate tank, mixer, pumping and insulation)[1]	27,520
Microturbine (100kW$_e$, incl. heat exchanger)[1]	183,500
Gas compressor and storage tanks for compressed and uncompressed fuel gas[1]	45,870
Wood storage for 120t of wood chips[2]	48,000
20% buffer for construction & auxiliary costs[2]	79,310
Total System Capital Costs	475,950

Notes: [1] - based on 2005 € values; [2] - based on 2010 £ values.

At this point, it should however be mentioned that those prices need to be treated with some degree of caution, which is due to two reasons: the first being that some of the technologies are only entering maturation at the moment, therefore so-called

'Economies of Scale' are not yet included in their pricing. Those economies of scale mean that with an increasing output of a given product due to it becoming established in the market, the producer develops a learning or experience effect which most likely results in lower per-unit output prices [6, 13, 183, 189]. This effect of decreasing incremental costs with increasing cumulative output is shown in Figure 9-2 [6].

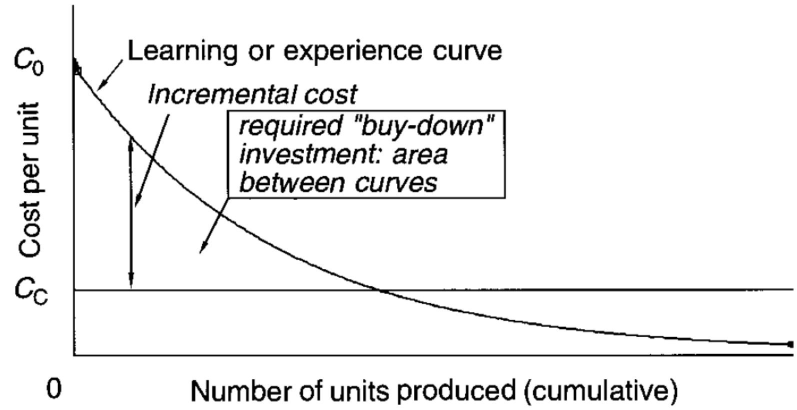

Figure 9-2: Effect of Economies of Scale on Per-Unit Prices (Source: [6]).

Economies of scale for industrial products can cause a reduction of per-unit prices between 15-25% for each doubling of output [6, 183, 189], so entering maturation can significantly impact the price of a product, an effect which is not included in the aforementioned costs. However, since factoring in those unknown future price developments would only increase uncertainties, only published and/or quoted prices were used for the analysis. Although the sensitivity analysis below will revisit this topic and undertake some evaluation of likely price changes, it should nevertheless be considered that prices can vary substantially.

The second point that should be noted is that since the plant design in this project is a novel design approach, it has as such not been assembled and marketed yet. Although the single technologies employed are all well-developed, the combination of the different technologies into the new plant design may result in higher installation costs of the plant system compared to installing its single units. This effect is mitigated by including the aforementioned conservatively sized 20% buffer for unexpected costs, however it should be noted that setting up a prototype plant will always bear some unknown risks on prices. This again will be evaluated further through the below sensitivity analysis of the buffer size.

9.1.2.2 Operation & Maintenance Costs

Costs for operation and maintenance (O&M) of a power system consist of regularly occurring costs, such as for labour to staff and administrate the plant, as well as for labour for maintenance and repair, and for replacement spares, lubrication etc. [5]. Although some of those costs occur irrespective of the amount of operation of the plant, such as those for regular maintenance work or for staff, most have a close interrelation with the level of plant operation. The more the plant is operated, the more maintenance will need to be undertaken, and the more consumables such as lubricants will be needed.

Since small power plants are normally not labour intensive and are likely to be operated fully automated, the amount of variable O&M costs for small plants is normally significantly larger than the amount of fixed O&M costs. Hence O&M costs are counted towards variable costs and are expressed on the basis of cost per unit of product. In this analysis, they will be expressed as cost per kWh generated and supplied.

Especially for small scale plants of relatively new technology and for long periods of operation, it is very difficult to estimate exact O&M costs. Once technology has been used for decades, it is normally well-known what and when maintenance will be necessary, and how much this is likely to cost. Similarly, for large scale plants planned maintenance intervals need to be scheduled far in advance in order to arrange for alternative power during the outage, so estimating those costs is somewhat easier. In contrast to that, the plant in this project is a micro-scale plant that uses some well-developed technologies but applies them in a new way, so it is difficult to estimate exact O&M costs.

However, especially for small power systems it is apparent that O&M costs are very low when compared to the initial capital costs of the plant [2, 6, 182]. It is thus reasonable for the purpose of economic analysis to calculate O&M costs as a percentage of the capital costs instead of trying to estimate them in detail, which may result in high levels of uncertainty. For small power systems of the size of this plant, values of 1-5% have been mentioned [2, 5, 135, 184]; given that the capital costs calculated above include some units that will not require maintenance, such as the wood storage or the fuel tanks, it was therefore decided to account annual O&M costs at 3% of the initial capital costs of the system, which translates to ca. £0.04 per kWh generated, a value that was also mentioned elsewhere [190]. Again, the sensitivity analysis below will cover to what extent variations of this evidently variable value will affect the overall economics of the system.

9.1.2.3 Fuel Costs

The final category of costs is those for fuel, which includes fuel production costs and transport costs to the point of demand, i.e. to the plant. Since the amount of fuel needed depends on the amount of power generated, fuel costs are closely linked to the level of operation of the plant and thus belong to the group of variable costs. Fuel costs are therefore calculated on a per-unit basis of fuel input or power output.

This plant system uses two main fuel inputs: wet biomass feedstock for the anaerobic digester, and dry biomass feedstock for the gasifier. Therefore, the provision of both feedstock streams needs to be analysed with regards to costs. In section 6.1 and Table 6-I above it was mentioned which amounts of fuel are needed to operate the plant, and these fuel inputs form the basis of the cost calculation of the following sections.

9.1.2.3.1 Dry Biomass

For dry biomass feedstock, it was decided in section 6.2.5.2 above to undertake the simulations and availability analysis on the basis of short rotation coppice (SRC). Therefore, this analysis will continue using SRC as feedstock for the gasifier in order to calculate feedstock costs.

SRC plantations result in a number of costs, such as for establishment, fertiliser and insecticide spreading, and harvesting the feedstock. In addition, transport of the wood chips to the plant and storage may be necessary. Of those activities, establishing the plantation is the one that accrues most of the costs, which are for soil preparation and cultivation, fertiliser and herbicide spraying, planting of the SRC cuttings, and the cost of the cuttings itself [186, 191]. Since SRC plantations have a lifetime of more than 20 years [161, 186, 191], those costs occur only once during the project cycle. Although this means that their establishing costs could also be spread over a longer period than 20 years, which would reduce the annual pro-rata cost, it was assumed for reasons of simplification that the establishment costs would need to be fully amortised within the 20 years of the project.

Fertilising costs of the SRC plantation normally consist of cyclically spreading Nitrogen, Phosphorous and Potassium (N, P and K) in order to boost plant growth; however, the necessary level of fertilising and thus its cost depends on the local circumstances [186, 191]. Furthermore, in this study it was assumed that instead of purchasing fossil-based fertiliser, the abundantly available and nutrient-rich anaerobic digester effluent would be used as fertiliser and for soil improvement, so the only fertilising costs are those of spreading the effluent to the plantation, which would be done continuously throughout the lifetime of the project and results in annual spreading costs. With regards to herbicide spreading, it was mentioned that this again depends on the individual circumstances, but in many cases will not be necessary at all once the plantation has been established [191]; consequently, herbicide spreading was only accounted for during the establishment period.

Finally, harvesting costs occur once every three years, since SRC is harvested triennially. The crops are cut back at the root, chopped into wood chips and stored for later usage. Based on literature values [135, 186, 191], harvesting costs were estimated for the amount of SRC calculated. Following from the triennial harvesting cycle and the continuous gasifier demand, storage will be required to store sufficient feedstock between two harvesting cycles; this means that the storage will need to be dimensioned to store the whole harvest, which will be used during three years of gasifier operation. Wood chips can be stored in separate storage sheds or simply on ground, covered or uncovered; however, to minimise decay or contamination that are likely to occur when wood chips are stored on ground [157], it was chosen to calculate costs for separate storage buildings. Using literature values [186, 191], the costs of erecting storage buildings for the SRC harvest was calculated; since those costs only occur at the beginning of the project, i.e. when the storage is erected, they were included in the capital costs, which are shown in Table 9-I above.

Based on the above calculations, Table 9-II shows the total costs for providing SRC wood chips to the plant, and the years at which those costs will occur.

Table 9-II: Fuel Costs for SRC Wood Chips.

Cost Component	Cost per ha [£/ha]	Total Cost [£ 2010]	Years When Accrued
Establishment (spraying, fertilising, cultivating, planting, cost of cuttings, trimming)	1,330	53,200	1
Fertilising (spreading)	5	200	1-20
Harvesting (cutting, chopping, transport to storage)	350	14,000	3, 6, 9, 12, 15, 18, 20

Since those costs are calculated on a per-hectare of plantation area basis, the amount of wood chips needed by the gasifier from Table 6-I, and the average yield of SRC plantations from Table 6-X was used to calculate the surface area necessary for supplying sufficient wood chips to the plant. Using conservative yields, it was found that an area of 40 hectares would provide sufficient SRC wood chips to operate the plant accordingly. Therefore, in a final step the aforementioned per-hectare fuel costs were converted into total costs using the chosen plantation area, and these results are also shown in Table 9-II.

9.1.2.3.2 Wet Biomass

Finally, wet biomass feedstock will be used in the anaerobic digester reactor to convert it into biogas. It was decided in section 6.2.5.1 above that animal manure will be used as wet biomass feedstock for the simulation and availability analysis, so the fuel costs will also be calculated for animal manure.

It is mentioned in Table 6-I what amount of manure is necessary for the digester in order to continuously produce the required amount of biogas. This means that this amount of manure will need to be provided on an ongoing basis, and a similar amount of digester effluent (or digestate) will need to be discharged. Therefore, the fuel costs of the wet biomass consist of the transport costs of transporting manure to the digester and of transporting effluent from the digester, and the costs of the manure itself.

The capital costs of the anaerobic digester mentioned above include costs for a separate effluent storage tank so that the effluent can be stored and thus transported in alternation with the fresh manure. Thus the transport costs consist of a suitable vehicle that shuttles manure and effluent between the plant and the farmer, which can be calculated on the basis of literature values [14, 186] and amounts to a value of £9,000 per annum, or £2.25 per tonne of manure transported.

Estimating the cost of the manure itself however is very difficult, since values are hard to obtain due to a lack of 'marketability' of manure, and those values available are most likely calculated on the amount of energy that can be gained from it [186]. On the other hand, it is also mentioned that taking in manure could even result in a negative price, i.e. in getting paid to dispose of it [14]. Similarly, the nutrient-rich digester effluent could be sold off as fertiliser and for soil improvement, which would also justify a negative manure intake price. Taking all those considerations into account and since it was chosen to use part of the effluent as fertiliser for the SRC plantation (see section 9.1.2.3.1), it was decided to set a zero price for the manure, which means that it neither incurs costs nor obtains revenues to take it in as feedstock. Since the plant would be operated on local feedstock, it could for example be sourced from local farmers for free to save their disposal and treatment costs, and the remaining effluent which is not needed by the SRC plantation could be returned to the farmers as fertiliser and for soil improvement, which would provide incentives for both parties. Again, the sensitivity analysis below will undertake to evaluate the impacts on the economics should this assumption prove inaccurate.

9.1.3 Revenues

The revenue streams of a power system consist of the amount of power generated and supplied to the customers, multiplied with the price per unit of power. This means that the revenue streams for the economic analysis of such a project will also occur continuously over the lifetime of the plant. The plant provides power to a group of local residential customers, who will most likely pay for their power monthly, quarterly or annually. For simplification reasons, it was decided to apply annual revenue streams in the analysis.

The main revenue stream of the plant will evidently be the power supplied to the customers. The annual revenues can be calculated by multiplying the power generated as mentioned in Table 7-II above (in kWh per year) with the power price per unit (in pence per kWh). However, the prices for electricity will most likely not be constant over a period of 20 years, so whilst it may be a reasonable assumption to use current

UK average power prices [189, 192] to calculate the revenues of the first year of operation, it needs to be evaluated how to represent the price variations for the calculation of future revenues. It is likely that retail prices for power will increase over the next two decades, if only to cater for price increases of fossil fuel which the currently predominantly fossil fuel based power infrastructure depends on, and for the necessary investments in national power systems and grid infrastructure (as discussed in chapter 1). However, estimating exact future price developments is nearly impossible, thus the price increases were estimated on the basis of historical price developments of the last 10 years [192], and a resulting 6% rate of annual power price increase was applied for future revenues.

Since the discount rate was chosen with 8% as mentioned in section 9.1.1 above, this however means that the current value of those future revenue streams decreases, as they increase by 6% annually but are discounted at 8% annually (see also Figure 9-4 below). This was found to be a more conservative assumption than the current UK energy price forecasts [193] which assume a relatively constant current value of power prices between 2010 and 2025 for their average price projection, and increasing current value power prices for their high and very high price projections. In either case, similar to all other main parameters that influence the analysis results, the chosen annual price increase as well as the electricity base price per unit will also be subject to the sensitivity analysis.

Finally, it should be noted that the plant may also be able to generate other revenue streams. Those would mainly consist of governmental subsidies and of the selling value of its other product streams.

Numerous governmental subsidies for renewable power systems exist throughout the world and could be used to reduce the costs of setting up such a power system; however, it was chosen to exclude all possible subsidies since they are not necessarily fixed and since it would be difficult to estimate a robust average value for such subsidies, given that the plant could be used in different areas or even countries. In addition, it will also be easier to conclude whether or what amount of subsidy would be necessary to incentivise the setting up of such a system on the basis of undistorted analysis results. If necessary, this evaluation could then be undertaken on a case-to-case basis with knowledge of the local subsidising regulations, which was decided to be a more reasonable approach.

Apart from those subsidies, some other product streams of the plant may also have an economic value and could generate income. Those streams would mainly be the char (i.e. the unconverted biomass) of the gasifier, and the digester effluent of the anaerobic digester. Whilst the char could be used within the process, it could also be sold for heat generation. Similarly, the digestate is rich of nutrients and could be used as a fertiliser or for soil improvement, as mentioned above. Thus both of these streams could in principle be sold as by-products. It was however chosen to indirectly include the value of the digestate in the economic analysis by using it as a fertiliser for the SRC plantation as mentioned in section 9.1.2.3.1 above, and similarly the char has not been included in the analysis since it might instead be used within the process. Therefore, and in order to obtain a conservative analysis basis, the generated power constitutes the only revenue stream of this plant system.

9.1.4 Economic Analysis Results

On the basis of the above single cost and income calculations, it is possible to estimate the annual cost and revenue streams over the 20 year period of the project. Since the capital costs need to be raised at the beginning of the project, it was decided to also include the costs of financing this investment over the 20 years of the project. This means that the capital costs were converted into annual repayments of the capital cost lump sum as calculated in section 9.1.2.1 and the interest accrued from the 8% discount rate chosen in section 9.1.1. However, none of the cost and revenue streams were adjusted for inflation, since the whole calculation was undertaken excluding inflationary effects, as mentioned in section 9.1.1 above. Figure 9-3 depicts the resulting annual cost and revenue streams for the 20 year period.

It can be seen that apart from the constant and relatively high annual share of financing the capital costs, the incurred first-year costs are the highest annual cost stream, as they include significant costs for the establishment of the SRC crop. After this one-time expenditure is accrued, the fuel costs for SRC are comparably small, as they only consist of the triennial harvest cost and a very small annual fertiliser cost component. Similarly, the operations and maintenance and the manure fuel costs are also relatively small. The total costs amount to an annual level of around £80,000 which needs to be amortised through the annual revenues.

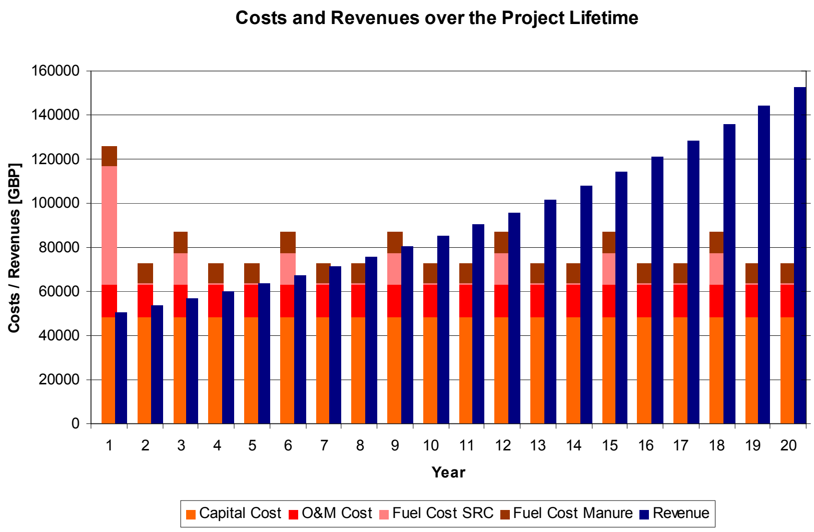

Figure 9-3: Annual Cost and Revenue Streams.

Figure 9-3 also shows those annual revenue streams, and due to the annual price increase as mentioned in section 9.1.3, they rise from around £50,000 in year 1 to around £150,000 in year 20. It can therefore be seen that in year 10 the revenue exceeds the costs for the first time, and that the plant revenues are significantly above the costs in the second half of the analysis period.

In order to understand the implications of those costs and revenue streams for the overall economics of the plant, and to find out whether an investment in this system will be profitable, it could thus be calculated whether the sum of all revenue streams exceeds the sum of all cost streams. However, this method would neglect the aforementioned discount effect stating that future money is worth less than current-value money.

Therefore, it was instead chosen to calculate an overall *Net Present Value (NPV)* that discounts all future cost and earning streams into a single amount of current-value money [6]. This net present value represents the current (2010) value of the total accumulated profit (or loss) that an investor would incur if s/he would set up and operate the plant for the project lifetime of 20 years. It uses the discount rate to correct future revenue and/or cost streams as mentioned in eqn. 9-1 and can be calculated as

$$NPV = \sum_{n=1}^{20} \frac{R_n - C_n}{(1+r)^n} \tag{9-2}$$

with R_n and C_n being the revenue or cost streams of year n, respectively.

As the discount rate and the rate for financing the capital costs were chosen with a base case value of 8% to include the profit expectations and risks for such a power system as discussed in section 9.1.1, it is coherent to use the same discount rate for calculating the net present value, as this value again expresses the overall profit or loss as a function of future capital costs [6]. The impact of discounting the future costs and revenue streams can be seen in Figure 9-4, which shows the annual costs and revenue streams from Figure 9-3, but converted into the current-value (2010) basis.

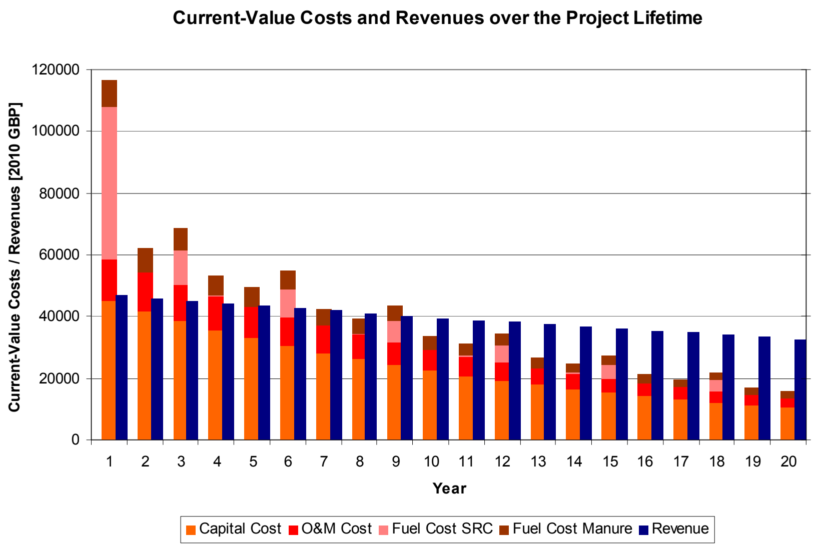

Figure 9-4: Current-Value Annual Cost and Revenue Streams.

Based on those corrected cost and revenue streams, the net present value for the plant can be calculated as -£14,500, which means that an investment in the plant incurring the aforementioned costs and yielding the aforementioned revenues over the period of 20 years would generate an overall loss of £14,500 in current value. Given the level of the annual cost and revenue streams, this means that the plant economics are highly balanced, as an overall present-value investment of £802,500 would yield overall present-value revenues of £788,000. Whilst it becomes apparent that this only slightly negative net present value already strongly indicates the economic potential of this plant, a number of points should nevertheless also be considered in order to fully acknowledge this result.

Firstly it should be remembered that since the plant technology is relatively new and since the design itself is a novel way of applying the technologies, the basis for the investment costs of this system as well as for all other incurring cost streams were very conservatively chosen price estimates. Similarly, the revenue streams were forecasted on the basis of current and historical prices and price changes. This however results in the obtained net present value having an immanent level of uncertainty, which means that it could fluctuate in one direction or another. This will be addressed in the sensitivity analysis below, however since the calculated net present value is relatively close to zero, it indicates that changes in one or several of the parameters can easily result in an overall positive, or overall negative, net present value.

Additionally, it was mentioned in section 9.1.3 above that no subsidies of any kind were included in the revenue calculation. Even though it is very likely that a plant system such as the one in this project would benefit from some form of renewable energy subsidies, it was chosen to not include them in the calculation as their amount depends on the location of the plant and its current regulations. However, the relatively balanced net present value indicates that this plant is a highly interesting option should some form of subsidy be available to compensate for the relatively low losses that a potential investor would face when setting up such a plant.

Finally, irrespective of the potential to earn further revenues for selling other product streams as mentioned above, there are also a number of soft-money factors which would influence the final decision-making process and could thus become pivotal given the relatively balanced economics; those soft-money factors will be described in the following section.

9.1.5 Soft-Money Factors

As was mentioned in the analysis of the previous section, only 'hard-money factors' were included in the calculations, i.e. parameters that can with some certainty be assigned with a fixed monetary value. This is a necessity in order to obtain robust results for both costs and revenues, and for the overall project economics. Whilst the immanent uncertainty of those hard-money values will be further discussed in the sensitivity analysis below, it should however be noted that for a decision-making process, there are a number of costs and benefits that are not easily expressed through monetary values even though they will influence the result.

Those costs and benefits are mainly socioeconomic and psychoeconomic factors and are defined as 'soft-money factors'. Even though it is very difficult to assign them with fixed values, they can nevertheless significantly shift the outcome of a decision-making process towards one of several alternatives [2, 194]. So although it was chosen to exclude those parameters from the economic analysis in order to limit it to comprehensible assumptions, the soft-money factors nevertheless need to be noted and considered for any final decision. Therefore, this section will provide a short overview of the prevalent soft-money costs and benefits of this plant.

9.1.5.1 Outage costs

The main soft-money cost factor for the plant system is the implication of outages, i.e. the penalties that are incurred when the system is unable to satisfy demand due to planned or unplanned maintenance or breakdown. The loss of power supply to a residential customer is a strong cause for dissatisfaction since power is essential for several customer activities [195], which means that plant reliability and power availability are strong motivators for power customers. As mentioned in section 8.2.1 above, the reliability of any single decentralised power generator such as this plant is a magnitude lower compared to a remote grid connection. This means that if the plant is the sole power source for the customers, the length of time during which customers will not receive power will be around ten times higher than when they are connected to a grid network; see section 8.2.1.

However, it needs to be differentiated between the four possible modes of operation of the plant as defined in Figure 8-1 above, since they have different implications for the plant economics and for the outage costs. Should there be no grid connection available and the alternatives of power supply are either setting up the plant running in stand-alone mode or setting up a grid connection, but not both options together, then the lower reliability of the plant needs to be considered when comparing the plant investment to the grid connection investment. In case it is infeasible to set up a grid connection due to the remoteness of the customers, then the lower reliability of the plant in stand-alone mode will not be of much impact to the decision-making, as it is without alternative and as it will still enable the overall access to power.

However, if a grid connection is available, even though it might be prone to disruption due to its remoteness, then the plant can be operated in either parallel, micro-grid or roll-over mode, the latter of which has been found to be the preferred mode of operation (see section 8.2.5 above). In those cases, the lower reliability of the plant will be compensated by the higher reliability of the grid connection; on the other hand, it needs to be noted that in those cases the potential savings of replacing a grid connection would be lost. Section 9.1.6 will address these issues further.

In either case, the effects of power outages to the customer satisfaction need to be evaluated. Two different aspects of outages can influence the customer's attitude towards power losses, which are the duration, i.e. how long the outage lasts before power supply is reinstated, and the frequency, i.e. how often outages occur during the course of one year [5, 195]. Even though it is assumed that one long outage may cause less frustration for residential customers than short outages on a regular basis [5, 195], it is nearly impossible to evaluate which of the two parameters is more crucial.

In order to find a way to handle this problem, two alternative approaches were established in literature: the costs of outages could either be evaluated on the basis of the willingness to pay for avoiding the outages, or they could be evaluated by using the value of the effects of the outages [195]. It is reasonable to assume that the latter alternative is more realistic, since electricity as such does not provide direct satisfaction to the customers, but is instead used to operate other appliances that provide satisfaction. Therefore, trying to assign outages with a value representing the actual power loss, i.e. multiplying the annual hours of outage with the average consumption and the price of power, cannot be convincing, and even including the amount that customers would be willing to pay for higher reliability, such as for backup power, is a very difficult and vague approach, especially for residential customers whose willingness to pay is hard to establish [195].

Therefore, it is more reasonable to evaluate outage costs on the basis of the so-called 'value of foregone leisure' for the residential customer, which tries to establish the customer's valuation of his use of energy, which is lost during an outage. Evidently, this value of foregone leisure is closely linked to the time of the outage, since essential electricity consumption occurs in the early morning or early evening hours where the customers undertake most of their activities [5, 195]. At those times, a loss of power is seen as significantly more dissatisfying compared to when happening overnight. This trend is shown in Figure 9-5, which assigns an empirically established cost value of a one-hour power outage of US customers to the time of day [5].

On the basis of these empirical results and evaluations, it was then concluded that at times when power is of essential value for customers, the customer main income is an acceptable approximate measure for the value of foregone leisure, since the incremental monetary value of electricity consuming leisure activities, which is lost during an outage, roughly equals the main income [5, 195].

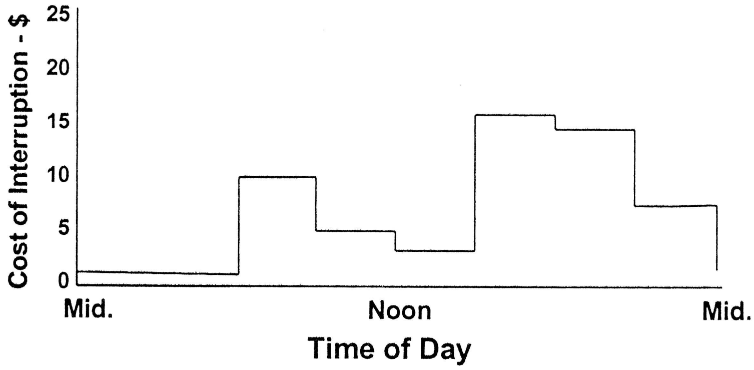

Figure 9-5: The Value of Residential Power Losses Over Time (Source: [5]).

Evidently, this result needs to be treated with some caution, as it tries to assign a fixed monetary value to an intrinsically soft-money factor; however, it provides an understanding of the value of outage costs that may need to be included in a decision-making process or when comparing different alternatives with different reliability levels, and should only be used as such an indicator.

9.1.5.2 Non-monetary benefits

Similar to costs that cannot easily be expressed as a monetary value, there are also a number of benefits that might influence a decision-making process, but are difficult to be assigned a hard-money value. Those so-called non-monetary benefits are mainly of socioeconomic and psychoeconomic nature, and although they have been excluded from the economic analysis, they need to be considered and will thus be covered in this section.

The two main non-monetary benefits of setting up such a local power plant are security of supply and the use of locally available fuel [2, 194]. Although they also influence hard economics by rendering fuel transport unnecessary and by reducing the dependency on volatile fossil fuel prices, they also have other positive effects in non-monetary terms. Using locally sourced fuel means that cash is spent locally, which is not normally the case when operating a power plant on fossil fuel. Furthermore, a local power plant system can also provide incentives for the local community to create jobs such as for establishment and harvest of the local fuel and thus increase prosperity to some extent [2, 7, 8, 194]. Whilst it is evidently difficult to assign a hard-money value to those medium to long-term effects, it should be mentioned that some governments subsidise decentralised power generation programmes for this exact reason [2, 8, 194].

Finally, several other non-monetary benefits exist, and even though some of those may not necessarily be economically relevant, they are mentioned for reasons of completeness.

Providing power locally instead of centrally tends to make the power system as a whole less vulnerable. Damage and fault of central power plants and the power grid and fuel transport infrastructure could substantially impact a national economy; compared to that, local power systems that are able to run in roll-over or stand-alone mode and with locally available fuel would not be impacted and could continue providing power [2].

Aesthetics and noise are also mentioned as benefits of smaller decentralised power systems, combined with reduced health & safety issues [2]. Large scale centralised power plants and extensive transmission and distribution systems are likely to cause a certain amount of noise, pollution and disturbance through fuel transport, and to avoid public concern are often located far away from customers. Decentralised plants such as the design in this project however are less intrusive since they are smaller, use locally available fuel, do not need an extensive grid system to transport power to the customers and in general employ technology with lower health and safety risks.

Finally, rural electrification in general has another more basic effect on the local societies. Since access to power is a necessity for most work and leisure activities, it has been found that electrified rural societies in general have a significantly higher living standard than those without access to power. This however means that providing local access to power may not only result in local jobs and increased prosperity as mentioned above, but could also enhance this development further by enabling substantial changes in living standards [7, 8, 194].

9.1.6 Comparison to Conventional Grid Connection

In order to understand how the plant system performs when compared to a conventional grid connection, the economic analysis of the previous sections will in this final section be compared to the cost impacts of power supply through the grid.

The general cost of power provision through a conventional grid connection comprises of the three cost factors for generation, transmission and distribution [2, 5, 6, 8]. In comparison, the cost of power supply through the plant design in this project comprises of generation cost, and of some costs for the local distribution cabling between plant and domestic customers.

For conventional power supply, it was mentioned in chapter 1 that generation, transmission and distribution is undertaken by different entities, which means that the final retail price of power constitutes of the costs of generation, transmission and distribution, and additionally including profit margins for the power generating company as well as for the transmission and distribution network operators. This final retail power price thus includes average capital, O&M and fuel costs for the power infrastructure as well as the aforementioned profit margins [5].

This however means that an indirect comparison of this plant with the conventional grid connection was already undertaken in the previous sections as those retail prices were used for the calculation of the revenue forecasts and thus for the plant net present value. However, whilst the retail prices do include an average cost component for infrastructure extension, the high costs of rural grid extensions is not normally represented, as only average grid maintenance and investment costs are included [5].

Therefore, when comparing the economics of the plant with the economics of power supply from a conventional grid connection, it needs to be evaluated what additional investment would be necessary to set up a conventional grid connection to reach the customers. The investment for such a grid connection can then be compared to the investment to set up the plant system in order to evaluate when the set up of the plant would break even with the set up of a grid connection, at which point a power supplier would incur the same costs for both options.

However, it should be noted that it needs to be differentiated between three possible circumstances before this evaluation can be undertaken. In case a grid connection is already available to serve the customers with power, then the plant could not offset those grid extension costs, but it could be used to support this grid connection and thus defer or render unnecessary grid upgrading costs. In this case the plant could be operated in roll-over mode as discussed in section 8.2.3, which would improve the reliability of the grid connection and thus the reliability of power supply to the customers.

When a grid connection is not currently available but it is possible to set it up to reach the customers, then the plant design would be able to replace the set up of this grid connection and it can then be calculated whether it would be more economical to set up a grid connection, or to use the plant off-grid. However, in this case it should be noted that the plant would be operated in stand-alone mode as discussed in section 8.2.4, which means that the plant would be the only power source for the customers and the plant reliability would thus determine the reliability of power supply to the customers. In this case, it might be necessary to further evaluate whether the lower reliability could offset the lower costs of power provision, which would need to include an analysis of the cost of power outages as mentioned in section 9.1.5.1.

Finally, in the rare case where the set up of a grid connection is virtually infeasible due to environmental factors such as the location of the customers or the terrain, a comparison of the plant economics with the investment for setting up a grid connection would be academic, as it would not be a real alternative. In this case, the only solution would be to operate the plant in stand-alone mode as discussed in section 8.2.4, from which follows that the plant reliability again determines the power supply reliability. In this case no further alternative would exist to increase reliability, which means that the plant reliability would have to suffice. This however would still likely be an improvement over not having any power access at all.

For those cases where the plant design could replace the set up of a conventional grid connection, it therefore needs to be evaluated what likely investment would be incurred by setting up a new distribution grid connection to serve the remote customers. The cost of power distribution lines mainly depends on the distance they need to span, the expected load from the customers and on the local terrain, e.g. whether it is a plain or hilly environment and how easy it would be to install the network cables [2, 5, 8]. From this follows that it is very difficult to assign average costs to the extension of a distribution grid to reach new customers, as those costs significantly depend on the circumstances of each individual case. However, although literature mentions that a wide range of costs from £20,000 up to £200,000 per km of network could be incurred, average distribution grid extension costs amount to around £65,000 per km of network [2, 5].

On the basis of those values, the likely investment for grid extension can be calculated as a function of the distance. These costs can then be compared to the net present value of an investment in the plant as calculated in section 9.1.4. Figure 9-6 shows the results of this calculation for the low, average and high cost scenario and thus depicts the critical distance which would result in a break-even of the plant investment costs and the grid extension costs.

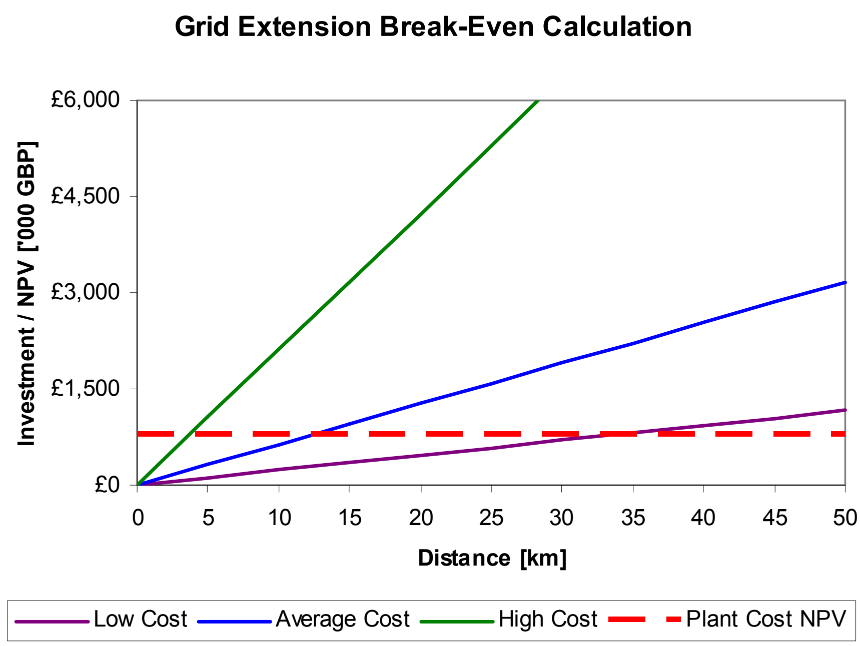

Figure 9-6: Grid Extension Break-Even Calculation.

It can be seen that whilst the plant design would provide an incentive over the set up of a grid connection for a distance of at least 4km in the high cost scenario, this critical distance increases to around 13km for the average cost scenario, and to around 35km for the low cost scenario.

However, at this point it should be mentioned again that these results, although indicative for the general trend, need to be treated with some degree of caution as the exact distribution costs may vary significantly, depending on the aforementioned factors. Furthermore, the net present value of the plant investment itself is also subject to uncertainties, which will be evaluated in the sensitivity analysis that follows this section.

After considering all those evaluations it can nevertheless be concluded that the critical distance needed for a break-even between the plant cost and the infrastructure costs of setting up a distribution grid connection is likely to be at a very interesting level, which means that this plant could provide significant incentives to replace a grid connection to reach remotely located residential customers.

9.2 Sensitivity Analysis

Having analysed the results of the economic evaluation in the previous sections, it becomes apparent that the final values obtained should be handled with some degree of caution. It is immanent to all economic analyses that uncertainties can significantly influence the obtained results. This is even more important when, such as in this case, analyses are performed over a long period in the future. Whilst it is arguably hard to obtain robust data for equipment prices and O&M costs for a technology that is comparably new, this becomes even harder when there is the need to forecast revenues or costs into the next 20 years. However, by choosing conservative values, a decent result can be obtained, and even though the absolute value might be arguable to some degree, it can at least provide a good basis for comparing one alternative to another.

The issue of uncertainty in modelling economics can also be overcome by performing a set of alternative analyses to include possible changes in some or all of the important and influential parameters. This methodology is known as sensitivity analysis [5, 6, 26, 135], as the aim is to understand the sensitivity of the overall results when some of the underlying (and uncertain) parameters are adjusted. It can thus be evaluated through sensitivity analysis how robust an obtained result is when changes in its parameters are likely, and it can be shown to what extent those changes influence the overall result. Thus, a sensitivity analysis tries to bridge the gap between the inherent uncertainties of any forecasting, and the need to obtain robust results. The following sections will describe the methodology of the sensitivity analysis employed for this plant and its results.

9.2.1 Sensitivity Analysis Methodology

In the context of the previous economic analysis, a sensitivity analysis will be performed for this project to evaluate the likely impact of variation in some of the underlying parameters. The single parameters used to develop the economic analysis in order to compare the overall investments with the overall revenues over the lifetime of the project were described in the above section. Most of those however are subject to uncertainty, especially with progression of the analysis into the future. Therefore, the following parameters were subjected to changes in order to understand their influence on the overall result of the economic analysis:

- discount rate for expected return on investment and financing costs;
- capital costs to account for economies of scale;
- percentage buffer of capital costs for other costs and auxiliaries;
- percentage of capital costs for operations and maintenance costs;
- obtained annual SRC yield to account for different environments;
- fuel costs of wood chips for establishment and harvest;
- fuel costs of manure for transport and buying/selling price evaluation; and
- revenues to account for different base prices and percentage in/decreases.

This means that all parameters that influence one or more of the cost components as shown in Figure 9-3 were included in the sensitivity analysis in order to achieve as much information as possible about how uncertainties might influence the results of the economic analysis.

Once the set of parameters to be subjected to variation was chosen, it then needs to be discussed what level of variation should be applied to each of the parameters during the study. Evidently, the chosen level of variation will represent the level of uncertainty and embodies the likely volatility in each of the parameters [5, 6, 26], which means that the larger the applied variations, the more information can be obtained on their influence of the result. For power system analysis, variation intervals of between 20-50% of the parameter value used in the base case were suggested in literature [5, 6, 135], and given that the plant applies technology in a novel way, it was chosen to apply a variation range of ±50% of the base case values used in section 9.1.

Having chosen both the parameters to be analysed and the level of variation, it can then be evaluated to which extent each parameter variation influences the economics as shown in Figure 9-3. However, this means that a different graph showing the annual cost and revenue streams would result for each variation, which makes comparing the results difficult. Instead, for the purpose of clarity it was thus chosen to evaluate the influence on the overall net present value from section 9.1.4 above. Since the net present value as a single number represents the overall current-value return or loss which an investment would accrue over the project lifetime, it represents the information contained in Figure 9-3, but is a better value to demonstrate the impact of parameter variation through the sensitivity analysis.

9.2.2 Sensitivity Analysis Results and Conclusions

Based on the aforementioned methodology, each chosen parameter was varied accordingly within ±50% of its base case value and the impacts of those variations on the net present value are shown in Figure 9-7.

It can be seen that four of the analysed nine parameters have a significantly high impact on the overall net present value; those are the applied discount rate, the plant capital costs, the revenues base unit price and the percentage of annual revenue increase. This result was to be expected, as the applied discount rate not only significantly influences the financing costs of the plant capital costs, but also the net present value as it discounts the future costs and revenues streams.

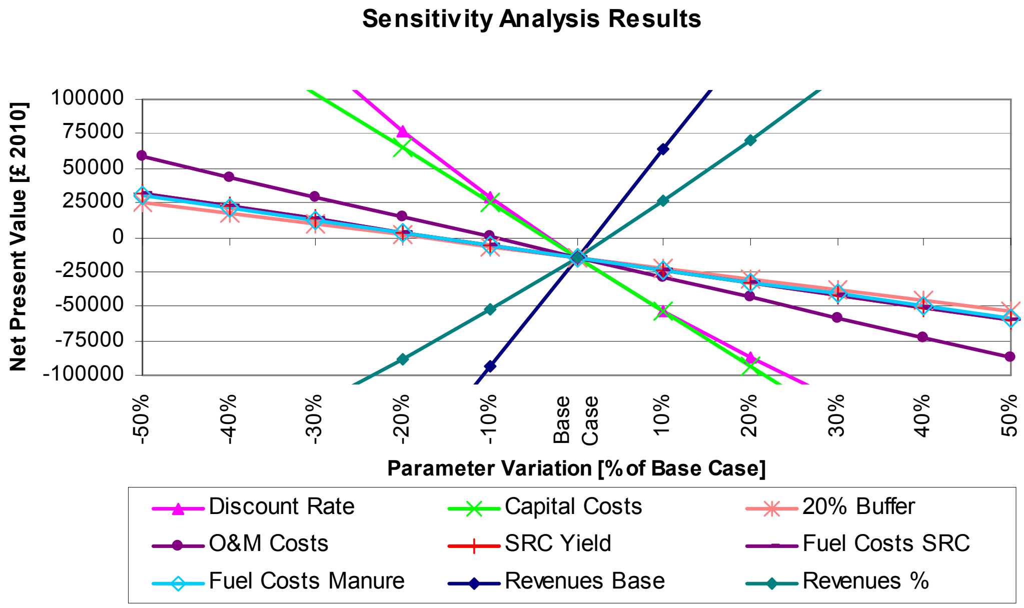

Figure 9-7: Sensitivity Analysis Results.

As is shown in Figure 9-3 and has been discussed above, the annual revenue streams increase from one year to another and exceed the annual cost streams from year 10 onwards, so a lower discount rate results in a higher impact of those future earnings on the overall net present value as they are discounted less. Therefore, a reduction in the discount rate of only 10% (i.e. from 8% to 7.2%) already trebles the net present value and results in it becoming positive, which means that the plant would not only pay back the financing costs but provide an overall return, in this case of around £28,500.

Similarly, the capital costs are the highest absolute cost component of the economic analysis so a variation in the level of capital costs would also significantly influence the overall result. A 10% reduction of the plant capital costs from £475,950 to around £430,000 would thus result in a similar effect on the net present value. This again shows the high hidden value of economies of scale as mentioned in section 9.1.2.1; given that the capital costs are likely to decrease with increasing maturity of the technology, the net present value can easily become positive and the plant could easily reach an interesting level of return, once the technology is applied more widely and prices start to fall.

The second main trend that can be seen in Figure 9-7 is the high influence of the two revenue parameters, i.e. the base unit price and the percentage of annual increase of this price. Of those parameters, the revenue base unit price has the higher impact, and increasing this parameter by only 10% results in the net present value increasing nearly five-fold. This can be explained by the fact that the revenue base unit price not only influences the revenue stream of the first year, but also all future earning streams which are based on the first year base unit price. Additionally, the percentage of annual increase of the unit price itself has a strong influence on the revenue streams similar to the discount rate, and adjusting the annual price increase from 6% to 6.6% also trebles the net present value from a negative to a positive level.

However, it should also be noted that the high impacts of the aforementioned four parameters in turn result in the economics being very vulnerable to increases of the discount rate and the capital costs, or to decreases of the revenues. An increase of, for example, the capital costs has a very detrimental effect on the net present value of the plant, which explains why it was crucial to choose the aforementioned conservative values for those parameters in order to obtain a robust initial result.

Compared to those main parameters, the remaining factors have an overall lower impact on the plant economics, even though they can still change the net present value by around 50-100% for each 10% of parameter adjustment. Of those factors, the operations and maintenance costs has the highest impact as it is the highest of the remaining cost components, whilst the fuel costs and the SRC yield are considerably less critical.

Finally, it should also be mentioned that the obtained impacts of each single parameter on the net present value would accumulate in case several parameters are adjusted. This means that a reduction in operation and maintenance costs and in capital costs of 10% each would quadruple the net present value, and a similar effect would occur for increasing those costs.

In conclusion it can thus be stated that the economics of the plant design mainly depend on the four factors discount rate, capital costs, revenue base price and annual revenue increase, and to a lesser extent on the remaining parameters. This also means that even though the base case net present value is negative, it can easily change significantly (to both sides) when only slight variations of one or several of the parameters evaluated in this sensitivity analysis occur. This shows both the high potential of this plant design to become very profitable over the long term and once the prices for the technology it employs start to reduce, but also the threat should the conservatively chosen prices turn out to still be higher, or should only lower revenues be achievable.

9.3 Efficiency Analysis

This final section will complete the previous economic evaluation of the plant by providing an analysis of the overall plant efficiency and the efficiency of generation and supply. Those results can then be compared to conventional grid power efficiencies to evaluate whether the plant could provide further benefits with regards to efficiency of supply.

Efficiencies in general are the ratio between useable output divided by necessary input, where output and input can be on the basis of power, heat, work or another form of energy [26], i.e.

$$\eta = \frac{E_{Out}}{E_{In}} . \qquad (9\text{-}3)$$

This means that for each unit or system, its efficiency can be calculated by analysing the energy flows of the system and by defining which energy flows are input and which are output flows. In case several output streams exist, it also needs to be defined which of those are useable, and which are losses. In order to enable a comparison of the chosen plant design and operation against conventional power supply options, efficiency analysis is a key element, and therefore the results of this analysis will be used to compare the plant efficiency with the efficiency of a conventional grid connection in section 9.3.5 below.

9.3.1 Conversion Technology Efficiency

Since two conversion technologies are employed in the plant, i.e. gasification and anaerobic digestion, two conversion technology efficiencies can be calculated. The energy flows through the conversion technology systems can be defined as follows: the input stream is the amount of chemical energy stored in the biomass feedstock, and the output stream is the amount of chemical energy stored in the fuel gases. The difference of these two values can be deemed as lost in the conversion process or converted into heat.

This limitation of the process efficiency to the basis of stored chemical energy is necessary due to the high levels of internal heat use throughout the plant design, and in order to achieve a suitable and consistent basis for calculations. Since the biomass feedstock is provided at ambient temperature for both processes, thermal energy of the feedstock does not need to be included as input for the efficiency calculation. However, both the producer gas and the biogas streams are of higher temperature when they leave the conversion reactors, thus part of the chemical energy that was stored in the biomass feedstock is converted into thermal energy of the fuel gas streams through conversion. On the other hand, thermal energy is also provided throughout the processes by means of hot gasification air or through heating of the anaerobic digester tank. Therefore, thermal input and output streams exist. However, the thermal energy streams of the plant design are only used internally, which means that the only useable end product of this plant is generated power to meet customer demand. In order to obtain a consistent overall plant efficiency, it necessarily needs to be limited to generated power as the useable output, and chemical energy stored in the biomass feedstock as input. It was hence chosen to exclude all internal input and output heat streams from the efficiency calculations, as they would be outputs from one and inputs for another system, but with no net effect on the whole system efficiency, which will be explained in section 9.3.4.

The gasification efficiency η_{GASIF} can be calculated as the ratio of chemical energy contained in the producer gas, divided by the chemical energy stored in the dry biomass feedstock to be used for gasification. The input energy can be calculated by using literature values for the heating value of dry biomass feedstock [18, 196], its mass flow rate and its moisture content. The useable output energy flow of the producer gas can be calculated by using its mass flow rate and computing its heating value on the basis of its composition as mentioned in Table 6-III above [197][10]. On this basis, the resulting gasification efficiency η_{GASIF} becomes

[10] It should be noted that these heating values are on a mass-basis, whilst the values mentioned in chapter 6 were on a volume-basis.

$$\eta_{GASIF} = \frac{\dot{E}_{PRODGAS}}{\dot{E}_{BIOMASS\_DRY}} = \frac{6.43\frac{MJ}{kg}\cdot 112.10\frac{kg}{h}}{20.01\frac{MJ}{kg}\cdot 112.5\frac{kg}{h}\cdot 0.4} = \underline{\underline{0.80}} \tag{9-4}$$

An efficiency of 70-80% for small-scale gasification systems in operation was also mentioned in literature [38, 46, 134, 135], so this calculation is further proof that the model is realistic.

The anaerobic digestion efficiency η_{AD} can be calculated on a similar basis, as it is the ratio of chemical energy of the biogas produced divided by the chemical energy of the wet feedstock. The chemical energy of the feedstock can again be calculated by using literature values for the wet feedstock heating value [196], its total solids content and its mass flow rate. The useable output energy flow can be calculated by using the computed biogas heating value on the basis of its composition as mentioned in section 5.2.3, and its mass flow. The resulting anaerobic digestion efficiency η_{AD} then becomes

$$\eta_{AD} = \frac{\dot{E}_{BIOGAS}}{\dot{E}_{BIOMASS\_WET}} = \frac{16.72\frac{MJ}{kg}\cdot 13.27\frac{kg}{h}}{13.34\frac{MJ}{kg}\cdot 458.3\frac{kg}{h}\cdot 0.1} = \underline{\underline{0.36}} \tag{9-5}$$

Since the anaerobic digestion system was modelled by using conversion and methane generation rates of similar operational plants, a resulting efficiency of 36% therefore compares well with the plants on which the model was based [31, 84, 125].

An overall conversion technology efficiency η_{CONV} can then be calculated on the basis of the two energy flows from gasification and anaerobic digestion as

$$\eta_{CONV} = \frac{\dot{E}_{PRODGAS} + \dot{E}_{BIOGAS}}{\dot{E}_{BIOMASS\_DRY} + \dot{E}_{BIOMASS\_WET}} = \underline{\underline{0.62}} \tag{9-6}$$

9.3.2 Microturbine Generation Efficiency

The microturbine power generation efficiency η_{MT} can be calculated as the ratio between power generated by the microturbine and the chemical energy of the fuel gas. Again, it should be mentioned that besides the chemical energy streams, there are thermal energy streams as both input and output, i.e. in the form of hot exhaust effluent gas from the turbine as well as the amount of heat transferred to the combustion air in the microturbine heat exchanger. However, this calculation was again limited to the actual chemical energy of the fuel gas and the resulting power output since the heat is being used internally.

The output power of the microturbine is its net shaft power for the base case as mentioned in Table 6-II. Since the fuel energy flow rates are on a per-hour basis, this power is also converted into a per-hour energy flow. The input energy flow can be calculated based on the heating values of the biogas and producer gas from eqn. 6-1 (converted to mass-basis) and their respective mass flow rates. The microturbine power generation efficiency η_{MT} then becomes

$$\begin{aligned}\eta_{MT} &= \frac{P_{SHAFT}}{\dot{E}_{BIOGAS} + \dot{E}_{PRODGAS}} \\ &= \frac{72.55kW \cdot 3600\frac{s}{h}}{(16718.56\frac{kJ}{kg} \cdot 13.27\frac{kg}{h}) + (6428.53\frac{kJ}{kg} \cdot 112.10\frac{kg}{h})} = \underline{\underline{0.28}}\end{aligned} \tag{9-7}$$

This calculated microturbine power generation efficiency of 27.7% is very similar to the microturbine operation efficiencies mentioned in section 4.3.2.1 above, as should be expected.

Since the microturbine will partially be running on less than full nominal load during the operation period, its generation efficiency will be impacted, as has been described above. Attention should be drawn to the fact that the shaft output power (72.55kW) must therefore not be confused with the actual power output level P_{ACT}, which varies between half and full nominal load (50-100kW), as shown in the example in Figure 6-6 above; see also eqns. 6-9 and 6-10. The calculated microturbine power generation efficiency η_{MT} thus is the resulting average efficiency of operating the microturbine between 50-100% of its nominal load levels for the respective ratio of its operation period.

9.3.3 Operation Efficiency

When calculating the operation efficiency of the plant, i.e. the percentage of possible generation that will be delivered to the final customers in order to meet demand, it is not realistic to assume that the possible shaft power mentioned above equals the actual equivalent generation for the six cases. This is due to two reasons: on the one hand, in addition to the power consumption for mixing and pumping of the AD reactor as discussed in section 6.2.1 above, distribution losses between plant and customer, and between the different units of the plant, will occur and have to be included. On the other hand, the daily generation is different for each of the six cases due to different demand levels for each case.

With regards to the occurring losses, it should be mentioned that for any generator intended to provide a group of customers with power, the geographical point of generation will be away from the point of demand. This follows from the logical fact that the generation unit, i.e. the microturbine in this design, needs to be physically connected to the group of customers, i.e. the individual households. Since power needs to be distributed from the point of generation to the point of demand, losses in distribution (P_{LOSS}) will occur; however, those losses will be relatively small when compared to conventional centralised power systems, as the plant will be located close to its customers. In addition, similar power losses will occur within the plant systems, i.e. between microturbine, fuel compressor and electric heater. Finally, P_{LOSS} also includes the power necessary for pumping and mixing of the AD reactor, which has been calculated as 10% of the AD energy demand (see eqn. 6-6). As this power demand is a continuous demand, it decreases the available shaft power to satisfy customer demand similarly to the distribution losses.

With regards to the variable daily generation pattern, it has been described in the above sections that the power demand fluctuates throughout the seasons. Since gas production rates are constant, this however means that excess gas occurs, which also impacts the operation efficiency, as the theoretical power that could be generated by using this excess gas (P_{THEO}, see also eqn. 7-10) is not used to meet demand. As a result, only a certain part of the possible shaft power will be used to satisfy the customer demand for each of the six cases, and this is defined as the equivalent generation power $P_{GEN,EQ}$. It can be calculated as

$$P_{GEN,EQ} = P_{SHAFT} - P_{LOSS} - P_{THEO} \tag{9-8}$$

To compute the equivalent generation efficiency $\eta_{GEN,EQ}$, i.e. the ratio between possible shaft power and equivalent generation during operation, it is necessary to calculate the average of the equivalent generation power for all cases.

This can be achieved by using the values of each actual daily generation ($P_{GEN,C}$ in kWh/d) from Table 7-II, and the allocation of calendar days per year and case (D_C)

from Table 7-I, with *'C'* as the case denominator. An average equivalent generation $\overline{P}_{GEN,EQ}$ can then be calculated as

$$\overline{P}_{GEN,EQ} = \frac{\sum_{C} P_{GEN,C} \cdot D_C}{364} = \underline{\underline{1491.93 \tfrac{kWh}{d}}} \tag{9-9}$$

The equivalent generation efficiency $\eta_{GEN,EQ}$ can then be calculated as the ratio between this average equivalent generation and the possible shaft power, and it becomes

$$\eta_{GEN,EQ} = \frac{\overline{P}_{GEN,EQ}}{P_{SHAFT}} = \frac{1491.93 \tfrac{kWh}{d}}{72.55kW \cdot 24 \tfrac{h}{d})} = \underline{\underline{0.86}} \tag{9-10}$$

This means that when operating for one year on the patterns as defined above, the amount of power actually generated will be 86% of the possible shaft power generation. The remainder consists of the theoretical power not being generated and being available in the form of excess gas for feedstock pre-treatment (i.e. 8.2%, see section 7.2.4), and of the power used for own consumption and/or lost during power distribution.

On the basis of these results, the final actual generation efficiency $\eta_{GEN,ACT}$ can be calculated as the ratio between the average generated power and the average demanded power. To obtain this value it is necessary to compute the actual amount of power demanded by the customers for each of the six cases ($P_{DEM,C}$), and these values are shown in the second column of Table 9-III, together with the values for $P_{GEN,C}$ and D_C for the six cases.

Table 9-III: Actual Daily Power Generation and Demand and Allocation of Calendar Days.

Case Name	**$P_{GEN,C}$ [kWh/d]**	**$P_{DEM,C}$ [kWh/d]**	**D_C [-]**
Winter weekday	1624	1136	65
Winter weekend	1624	1176	26
Shoulder weekday	1470	981	130
Shoulder weekend	1475	1018	52
Summer weekday	1400	930	65
Summer weekend	1403	949	26

An average demand $\overline{P}_{DEM}$ for all cases can then be calculated by using these actual demand values and the allocation of calendar days per year, similar to the average equivalent generation above, as

$$\overline{P}_{DEM} = \frac{\sum_C P_{DEM,C} \cdot D_C}{364} = \underline{\underline{1016.61 \tfrac{kWh}{d}}} \tag{9-11}$$

Using this value, the actual generation efficiency $\eta_{GEN,ACT}$ can then be computed as

$$\eta_{GEN,ACT} = \frac{\overline{P}_{DEM}}{\overline{P}_{GEN,EQ}} = \frac{1016.61 \frac{kWh}{d}}{1491.93 \frac{kWh}{d}} = \underline{\underline{0.68}} \tag{9-12}$$

This means that of the total amount of power generated, 68% are actually delivered to the customers in order to meet their demand. As mentioned in section 7.2.3 above, the remainder is the amount of power to be used within the process for either the fuel compressor or the electric heater, see eqn. 7-6.

9.3.4 Total System Efficiency

Having calculated the aforementioned efficiencies for each part of the plant, a total efficiency for the plant can be computed, which provides the ratio between the power eventually delivered to the customers, and the chemical energy of the initial wet and dry biomass feedstock. This total system efficiency η_{TOT} can be calculated as

$$\eta_{TOT} = \eta_{CONV} \cdot \eta_{MT} \cdot \eta_{GEN,EQ} \cdot \eta_{GEN,ACT} = \underline{\underline{0.10}} \tag{9-13}$$

This means that for each unit of energy in the form of power delivered to the customer (useable output), around 10 units of chemically stored energy in wet and dry feedstock will have to be provided to the plant (input). At this point it can be seen that there is no net effect of excluding the heat streams from the calculation of the single efficiencies when analysing the whole system. To clarify the meaning of the total system efficiency and of the individual unit efficiencies, Figure 9-8 provides an energy efficiency flow chart which graphically depicts the energy input and output streams as well as the sources for losses.

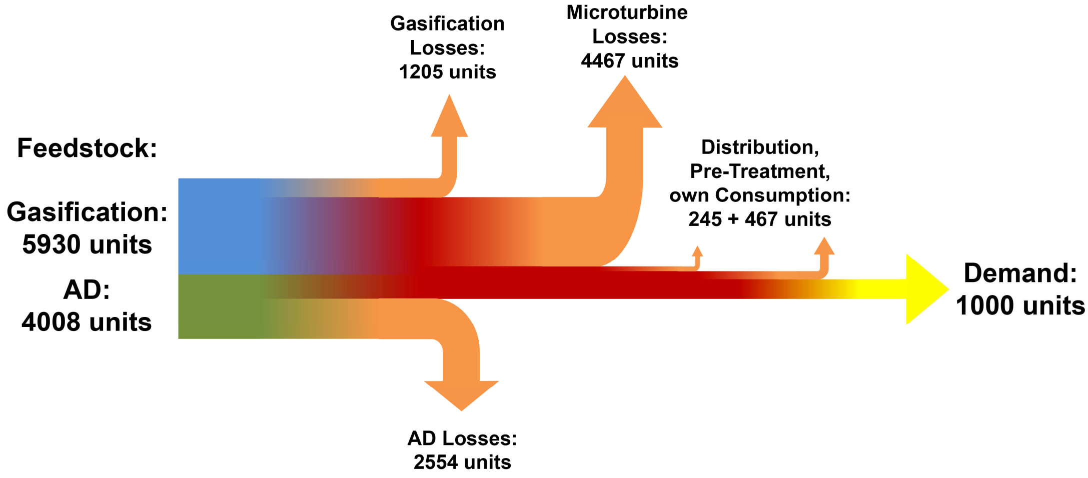

Figure 9-8: Plant Energy Efficiency Flow Chart.

A total system efficiency of 10% for the highly flexible generation to satisfy domestic customer demand is a respectable result, and it will be compared with the efficiency of conventional grid power in the following and final section.

9.3.5 Comparison to Conventional Grid Connection

After the operating efficiency of the plant design was calculated in the previous section, this section will compare those results with the efficiency of conventional power generation and supply.

As mentioned in chapter 1, the current conventional power system is a heavily centralised system where power is generated in large scale central power plants and then supplied to the customers through transmission and distribution grid systems. Power losses occur at each step of this system, which means that an overall system efficiency can be calculated, consisting of the single efficiencies of generation, transmission and distribution. Figure 9-9 [4] shows the resulting energy efficiency flow chart of the UK power system for 2008 [in TWh].

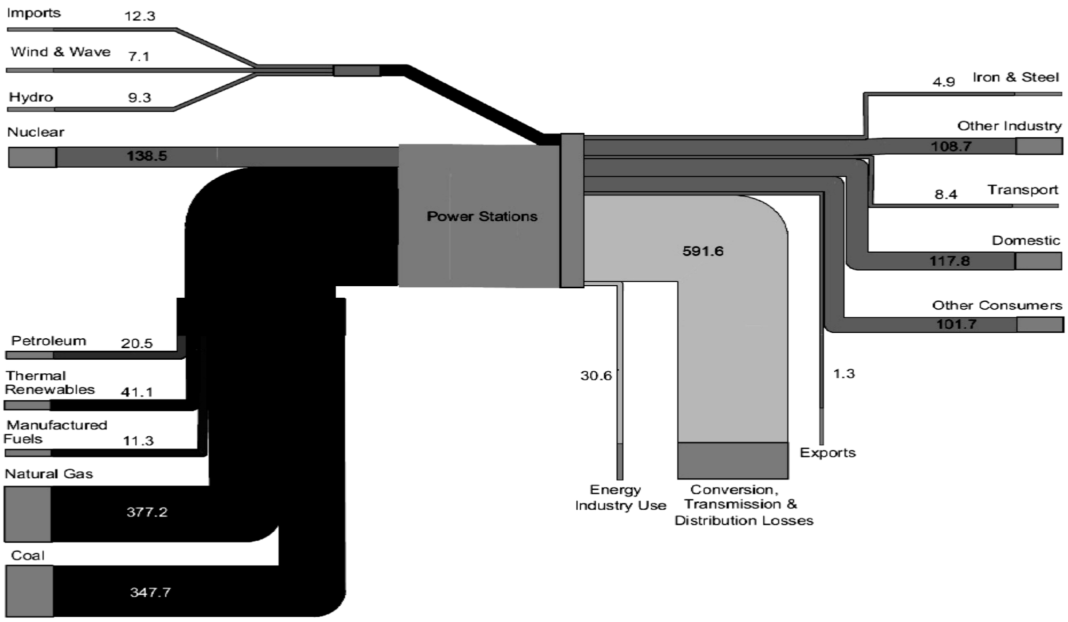

Figure 9-9: UK Power System Efficiency Flow Chart (Source: [4]).

In order to calculate the overall system efficiency, the total fuel input, consisting of all streams to the left of the '*Power Stations*' block, can be calculated as 965TWh. The usable output of the system is the power supplied to the customers, which consists of the streams to the right of the '*Power Stations*' block excluding those for losses and own consumption. This output can be calculated as 342.8TWh, resulting in a total system efficiency of 35.5%.

It thus becomes apparent that significant energy losses occur in the conventional UK power system. Those losses are mainly generation losses within the power stations,[11] and to a lesser extent transmission and distribution losses as well as own consumption [4]. Since most large-scale power plants are steam turbine or other thermal plants, a significant amount of energy is lost in the generation process through heat, which normally cannot be used within the plant system and is thus stacked [4]. As mentioned in chapter 5, one reason to aim for a high level of internal heat usage for

[11] It should be noted that the title 'Conversion, Transmission and Distribution Losses' in Figure 9-9 is somewhat misleading, as this category consists of generation, transmission and distribution losses, whilst conversion losses are excluded; see also below.

the plant design in this project was to mitigate this significant energy loss of conventional power plant systems.

However, the conventional power system has an overall efficiency exceeding that of the plant design in this project, which was calculated as 10% in eqn. 9-13. This is a finding that had to be expected due to several reasons, one of which is the sheer size difference between the plant design in this project, and the conventional power system. The economies of scale predict that a larger power plant will have a higher efficiency than a smaller plant [2, 5], which means that the large scale power plants on which the conventional power system heavily depends (see Table 1-I) are very likely to exceed the efficiency of a micro-scale plant such as in this project.

In addition, the current conventional power system needs to satisfy a significantly more balanced average load when compared to the load profiles that the plant in this project needs to supply power to. It can be seen from Figure 9-9 that domestic demand only constitutes around a third of the total power demand of the conventional power system, which means that this demand is less volatile than the one used in this project which solely consists of domestic demand[12]. This however means that it is possible to optimise the conventional power plants to operate on a high load factor which increases their plant efficiency, whereas the plant in this project needs to be operated flexibly and on a lower load factor to closely follow the demand.

Furthermore, the efficiency calculation for the conventional power system describes the average efficiency to supply power to all customers in the UK. Whilst average transmission and distribution grid losses account for around 5-10% of demand in the UK and other countries [2, 4, 5, 177], they depend on the distance between power plant and customer and increase with increasing distance [2, 5, 177]. This however means that the actual transmission and distribution grid losses will be higher for a more remotely located customer, and lower for more urban customers. Since this plant was specifically developed for remote customers, this in turn means that it would replace a grid connection with above-average transmission and distribution grid losses, and thus with a below-average efficiency.

[12] See, for example, the difference between the GB transmission system load profile depicted in Figure 1-4, and the load profiles of this project depicted in Figure 7-5.

In addition, the conventional power system efficiency is calculated on a different basis than the efficiency for this plant. The fuel streams shown in Figure 9-9 are fossil fuels already conditioned for power generation, whereas the fuel streams for the plant in this project are raw biomass feedstocks. This however means that conversion losses are excluded from the conventional power system efficiency calculation, whereas the plant efficiency includes those losses. The conversion technologies form an integral part of the plant design in this project, but fuel conversion is not normally a component of conventional power systems, so excluding conversion losses from the overall efficiency calculations would provide results which are more comparable, but meaningless. For the purpose of clarification and illustration only, the plant efficiency could be calculated as 16.2% if its conversion efficiency (η_{CONV} in eqn. 9-13) would be excluded.

Finally, it should also be noted that the predominant majority of the fuel used in the conventional power system is fossil fuel of high quality, whereas the plant system developed in this project uses waste biomass feedstocks. It thus has to be expected that a system which was developed for the use of high quality fuel will outperform a system that uses waste feedstock of relatively low quality.

Those considerations however lead to an important conclusion: focusing solely on high system efficiency cannot be constructive. Instead, considering the circumstances of a situation, such as distance or the choice and quality of fuel, may significantly influence the importance of efficiency and may justify lower overall efficiencies.

From the findings of the combined economic, sensitivity and efficiency analyses of this chapter it can therefore be concluded that the plant economics provide a near-balanced net present value, with a total investment of £802,500 yielding a total return of £788,000 over the 20 years of the project, not considering any soft money factors or subsidies. The sensitivity analysis undertaken however revealed that those results are very susceptible for changes in a number of key parameters, which can influence the net present value either positively or negatively. Comparing this investment to setting up a grid connection in remote areas, the break even distance was calculated as between 4-35km, depending on the costliness of such a remote grid connection. Finally, the efficiency analysis shows that there is a significant incentive for deployment of this system, even though the plant efficiency is below the efficiency of a conventional power system.

10 Summary of Results, Conclusions and Further Work

The previous chapters have guided through the steps of the project from choosing suitable technology, through developing, modelling and simulating the plant system, to the economic and efficiency analyses. In this final chapter of the thesis it is thus time to revisit the results obtained throughout this project, and to compare them with the objectives of the project as laid out in chapter 2. This can then lead to a conclusion on whether, and to what extent, this project has achieved its aim. Thereafter, it can be decided what further work could accompany this project in the future.

The results obtained throughout this research will be presented in the form of a SWOT analysis; this is a standard approach used in engineering and energy analysis to structure results of an obtained solution in the context of given aims or objectives [198]. Through a SWOT analysis, the obtained results of a solution are classified as Strengths, Weaknesses, Opportunities and Threats with regards to whether they are helpful or harmful to reach the aim or objective, and whether they are based on internal or external factors. Figure 10-1 depicts this classification.

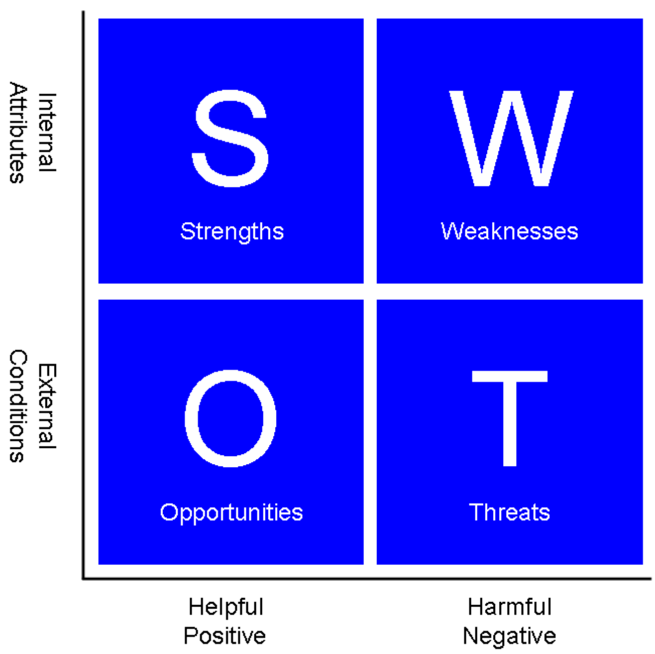

Figure 10-1: SWOT Analysis Category Description.

Using this classification, the results obtained throughout this project can be structured as follows.

Strengths

- By applying biomass conversion and generation technology which has been deployed for decades and proven to provide robust results, a novel design for a flexible micro-scale power plant has been developed (chapter 4).
- The choice of technology has led to a system which can not only be operated on a broad range of different feedstocks, but also minimises maintenance and outage times and thus permits very long continuous operation cycles without the necessity of skilled personnel (chapters 4 and 5).
- A detailed plant model was developed using conservatively chosen model parameters, and the model provides results that realistically represent operating units (chapter 5).
- It was proven that this plant system can be scaled to a size representing a remote village of around 120 houses with ca. $100kW_e$ peak load, and that it is thus at least an order of magnitude smaller than existing biomass power plants (chapter 6).
- The size of this power system and the possibility to scale it according to the demand together with its robustness result in a modular and mobile power plant solution that can be deployed in difficult-to-reach regions of developing countries and likewise in remote regions of developed countries (chapters 4-6).
- The operation of the plant was proven through extensive simulations on the basis of detailed load profiles, and the system was found to be able to accommodate highly fluctuating residential demand through flexible generation, thus enabling continuous power supply (chapter 7).
- This ongoing operation can be facilitated without power storage, by using the internal power sinks and the fuel storage of the plant to provide capacity for flexible generation. This provides benefits compared to the use of expensive batteries that need to be maintained, replaced and disposed of (chapter 7).
- The system can be operated both grid-connected (in roll-over mode) and off-grid (in stand-alone mode), which means that it can either replace or support a rural grid connection. From this follows that it can thus be used for both rural

electrification and as an alternative for utilities facing high infrastructure costs for grid extension or upgrade (chapter 8).

- The plant economics show a slightly negative overall net present value over the 20 year project period and are thus very interesting when compared to remote grid connections, especially for very remote regions where conventional grid connections become prohibitively expensive. The plant also achieves an acceptable operating efficiency when compared to conventional power supply, especially considering the quality of its feedstock (chapter 9).

Weaknesses

- One historical obstacle of gasification was obtaining clean producer gas, which explains why tar and other impurities have limited the application of especially small scale gasifiers. However, a number of novel gasifier designs were developed recently, using high temperature heat streams to internally crack tars in the producer gas and resulting in very clean gas streams. For this plant design, a clean producer gas is evidently necessary, thus it is crucial that a suitable gasification system is incorporated in the plant design (chapter 4).
- The technology for conversion and generation of this design has been used for decades, but the novel way of assembling the plant means that some degree of uncertainty remains. By using very conservative values during modelling and simulation and by comparing the obtained results with operational systems, the possibility of unforeseen circumstances was minimised. However, it is immanent to all modelling studies that those uncertainties remain unless an operational prototype of the plant exists (chapters 4 and 5).
- Sourcing local biomass feedstock as fuel for the plant limits its deployment to regions where such feedstock exists, from which follows that the plant design cannot be upscaled indefinitely as at some point feedstock demand will exceed availability (chapter 6).
- This system has been designed for a rural area with a relatively low power demand, which means that it would be unlikely to deploy it in an urban environment where a high power demand is combined with only a small area that could be used for feedstock cultivation or harvest (chapters 6 and 7).

- When operating the plant in off-grid mode as the only generator, the reliability of the plant determines the reliability of power access, but the plant can replace a costly grid connection. In contrast, when the plant is operated in roll-over mode to support such a grid connection, it can increase its reliability but cannot save these costs. From this follows that there will always be a trade-off between the two alternatives of operation, which depends on the circumstances (chapter 8).

Opportunities

- By using local biomass feedstock that can be sourced continuously without depleting local resources, and by applying technology which permits operation on a broad range of different feedstocks, the plant can be adjusted to different environments depending on the local availability of biomass (chapters 4 and 7).
- The possibility to deploy this plant in numerous regions and for different customer groups due to its modularity and scalability could significantly improve the plant economics through efficiencies of scale following an increase in production numbers of this system (chapters 6 and 9).
- The economics of the plant design are very receptive for incentives such as subsidies as the only slightly negative overall net present value means that relatively small incentives could make this system profitable and thus very interesting for both rural electrification and as a replacement for remote grid connections (chapter 9).

Threats

- The accommodation of transients and demand fluctuations is of high criticality for the system as it does not employ power storage, so load profiles need to be evaluated in great detail to ensure the plant is sufficiently sized and able to buffer those fluctuations before the design is to be deployed. The analyses in this context were based on high resolution data and the margins of safety show confidence in the results, however evaluating real load data of the customers that this plant is supposed to supply to would be highly recommendable (chapters 7 and 8).
- Since the plant could be deployed in a variety of different settings, other load profiles with significantly higher levels of transients may make power storage compulsory as the plant would otherwise not be able to operate. In the current

design, the implemented safety levels were found to achieve significant margins of safety for the highly transient load profiles that have been analysed, however for other load profiles batteries could become a last resort[13] (chapters 7 and 8).

- The plant economics are based on quoted and published prices as well as on forecasted revenues, but significant uncertainties remain, especially since this system incorporates a novel design. In the sensitivity analysis undertaken, those uncertainties were found to bear the potential to significantly impact the result of the economics, so a significant change in the circumstances, such as prices or revenues, could severely impact the overall profitability of this system (chapter 9).

Based on those findings, it can be concluded that the results obtained throughout this research have satisfied the aim of the project as laid out at the beginning, which was to develop a micro-scale biomass generation plant facilitating continuous power supply to remote residential customers.

Finally, this research was subject to typical project limitations with regards to time, resources and finances available. Therefore, it was necessary to limit this project to the objectives outlined in chapter 2 and to the results as discussed above. A number of further analyses could thus follow the research presented in this project. This possible and recommended further work is described as follows.

- It was mentioned in chapter 6 that the local availability of feedstock is crucial for the continuous and sustainable operation of the plant. It would thus be recommendable to evaluate biomass availability in several regions where this plant could possibly be deployed in order to understand whether sufficient feedstock is available. Such an approach was previously undertaken by other researchers for the West Cornwall region in England [182] and for the South West of England [88], which could be an interesting tie-in with the research presented in this project.

[13] It should however be noted that several microturbine designs which include batteries to accommodate power spikes in stand-alone operation mode are already available [120, 132].

- With further regards to feedstock, the plant design was chosen to be highly flexible in order to enable different feedstock sources to be used. Therefore, whilst this project has focused on Short Rotation Coppice as fuel for the gasifier and on manure as fuel for the anaerobic digester, other possible biomass feedstock sources could also be evaluated in more detail.
- In order to understand the environmental impact of this plant design during its whole lifetime, i.e. from production through use to disposal, a life cycle assessment of this system would provide interesting insights into the overall energy and carbon emission consequences of using such a plant. Life Cycle Assessment (LCA) is a tool to evaluate the complete, 'cradle-to-grave', embodied energy, carbon emissions and similar environmental factors of a product or process, in order to understand how this product performs in comparison to other alternatives [199-201]. Therefore, evaluating the resulting overall emissions and energy balances of employing such a system when compared to a conventional grid connection would be recommendable.
- Whilst this research has employed both detailed measured residential load profiles and modelled high resolution transient load profiles and found that significant margins of safety are achievable for the necessary accommodation of demand fluctuations, it is recommended that high resolution load profiles of a fitting size are obtained through measurement studies in order to confirm the findings with real data, which unfortunately is not openly available at present. This could ideally be combined with a detailed analysis of a typical rural village with regards to the aforementioned feedstock availability and variety.
- Similarly, other types of load profiles, such as from farms, apartment blocks or industrial customers, could provide further insight into the plant operation and interesting opportunities to evaluate whether the plant could also be used to supply those non-residential load profiles.
- Finally, it is highly recommendable to set up a physical prototype of the plant system to not only confirm that the conservative simulations undertaken in this research match the real operation of such a plant, but also to enable further evaluations of the ongoing and long-term operation of this system, as well as a better understanding of the economic implications.

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Appendix A – Related Publications

A number of publications have encompassed this project and are enclosed in this appendix. The following list provides an overview of those publications that have been published at the time of thesis submission.

I Journal Papers

1. Loeser, M. and Redfern, M.A., *Balancing power supply and demand in remote off-grid regions by means of a novel micro-scale combined feedstock biomass generation plant.* International Journal of Energy Research, 2010. **34**(11): p. 986-1001.

2. Loeser, M. and Redfern, M.A., *Modelling and simulation of a novel micro-scale combined feedstock biomass generation plant for grid-independent power supply.* International Journal of Energy Research, 2010. **34**(4): p. 303-320.

II Conference Papers

1. Loeser, M. and Redfern, M.A., *How Small can Micro-Scale Generation be? - Size analysis of a novel biomass power plant*, in *9th IEEE Annual Electrical Power and Energy Conference (EPEC09)*. 2009: 22-23 October 2009 Montreal, Quebec, Canada.

2. Loeser, M. and Redfern, M.A., *Novel Combined Feedstock Micro-Scale Biomass Generation Plant for Remote Power Supply - Modelling and Simulation Results,* in *17th European Biomass Conference & Exhibition (EBCE).* 2009, ETA-Florence: 29 June - 3 July 2009, Hamburg, Germany. p. 621-628.

3. Loeser, M. and Redfern, M.A., *Overview of Biomass Conversion and Generation Technologies,* in *43rd Universities Power Engineering Conference (UPEC).* 2008: 1-4 September 2008, Padova, Italy.

4. Loeser, M. and Redfern, M.A., *Micro-Scale Biomass Generation Plant Technology: Stand-Alone Designs for Remote Customers,* in *16th European Biomass Conference & Exhibition (EBCE).* 2008, ETA-Florence: 2-6 June 2008, Valencia, Spain. p. 1468-1477.

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Balancing power supply and demand in remote off-grid regions by means of a novel micro-scale combined feedstock biomass generation plant

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SUMMARY

Providing electricity to a group of remote domestic or industrial customers can be achieved by a grid connection, or by an off-grid (island) generator. While the former can become costly and will likely be prone to disruption, the latter is normally based on fossil fuels, which makes fuel sourcing and transport critical. To overcome these obstacles, a novel micro-scale biomass generation plant was developed. This plant uses locally available renewable biomass feedstock to generate decentralized power at the point of demand and without the necessity of a grid connection.

In this paper, load simulations on the basis of a process simulation model of the plant are performed to achieve a continuous match of supply and demand. It is analysed which load characteristics and fluctuations have to be expected when generating for a remote group of domestic customers, and it is evaluated how the plant needs to be operated to always provide sufficient power. Additionally, the fuel storage system of the plant system is investigated: The plant does not employ electrical storage, but instead matches demand and supply by means of internal usage of heat and power and through fuel storage. Relative and absolute storage levels as well as the storage charge/discharge cycles are analysed, and it will be shown that the plant can easily accommodate severe load fluctuations. Finally, the plant load factors are evaluated, and the findings show that this design is an interesting alternative to common island generators or to a conventional grid connection for remote customers.

KEY WORDS: micro-scale applications; decentralized electricity generation; stand-alone-systems; waste to power; gasification; anaerobic digestion; microturbine

INTRODUCTION

Providing electricity to remote areas currently results in two main options: setting up and maintaining a network connection to an existing distribution grid, or installing an island solution, based on fossil fuel-operated micro generators such as diesel engines and batteries to level out the demand and supply.

The distribution grid networks that exist in developed countries are however reaching an age which demands large-scale efforts for modernization

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and maintenance; additionally, questions of stability and reliability become more critical as the network is to be extended. In many developing countries, such infrastructure does not exist at all. Additionally, transmission losses increase with the length of the network, and thus especially for smaller remote developments it may not be economic to set up or maintain a grid connection [1–3].

The alternative to a grid connection is an island solution, which produces electricity close to the point of demand. It is however mainly based on fossil fuel technology, which makes fuel sourcing and transport important factors. Besides, these installations normally have high maintenance efforts for regularly replacing parts of the equipment, such as lubrication and batteries. Additionally, these rural electrification systems are currently only operated intermittently and for a number of hours per day, which means that the demand has to follow the available generation level [2,4,5]. In an environment of depleting fossil fuel sources and growing carbon awareness it may also not be suitable to set up 'dirty' fossil fuel generators, especially in remote and mostly rural areas.

To tackle all these obstacles, providing electricity at the point of demand by means of renewable and locally sourced energy carriers would be a highly interesting alternative. The main issue that such an option would need to overcome is that domestic and industrial demand for electricity is continuous, but fluctuating, which means that it varies over time. As electricity cannot be stored easily, generation therefore needs to follow the demand closely in order to provide reliable power.

Out of all renewables, only one fuel source can cope with such requirements: Biomass is available nonintermittently and can be easily stored; therefore, it provides major advantages over its competitors wind, solar or hydro power. Additionally, biomass in general is highly available, especially in regions that are remote and do not have grid connection, as they are normally close to agricultural amenities.

Most current biomass generation plant designs are optimized towards a large scale and therefore require a grid connection to match the supply and demand [6–8]. Given the comparably low energy density of biomass feedstock, sourcing and transport issues become critical for such systems [9]. Biomass-based generation can, however, also be adopted to provide electricity in a much more flexible way and in smaller scales. As long as sufficient feedstock is available for conversion into power, a biomass-powered plant can be operated to mirror load fluctuations in order to minimize or completely omit power import or export to a grid connection point. This design can then be scaled down to local power demand levels and thus large-scale applications and their problem of sourcing sufficient feedstock can be avoided.

The authors have developed a micro scale biomass-based power plant that is suitable to supply power on a flexible basis and that can be scaled to a level as small as $50\,kW_e$ [10]. This size can meet the typical power demand of remote villages or industrial customers such as farms. It also needs an amount of feedstock that can be provided locally and on an ongoing basis, and the fact that it utilizes both wet and dry feedstock additionally benefits and eases the local sourcing.

This plant, consisting of gasification and anaerobic digestion (AD) technology, converts biomass feedstock into a fuel gas, which is then used for generation in a microturbine (MT). The plant design was modelled in chemical engineering process software and after extensive feasibility studies the authors found that this design is both feasible and capable to generate electricity on a local level [11].

Special focus is laid on the fact that the plant design does not employ electricity storage at all. Instead of using large-scale battery stacks with their negative economic and ecological impacts, fuel gas storages form the integral storage systems of the plant. Fuel gas from gasification and AD is stored in order to be flexible enough to respond to load changes. This, combined with a power sink that uses the difference between power demand and generation to increase the system efficiency, results in a system that can provide power without the need to frequently exchange batteries and dispose of them.

This paper covers plant operation simulations that were undertaken in order to match the demand and supply. A network consisting of a

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number of domestic users and the power plant represents the application of the plant design in a remote village of domestic houses. It will be shown that the plant can be operated in a way that ensures continuous power supply to the customers without an external grid connection point.

To evaluate what level of flexibility is necessary and to understand the expected demand and its patterns, domestic load profiles will be analysed. These results will then be used to match the expected demand with suitable generation patterns, and special focus is laid on how to accommodate the load fluctuations. The plant design will also be analysed with regard to security of supply, robustness and reliability, and finally the storage facilities within the plant will be analysed and dimensioning issues will be addressed.

METHODOLOGY

Brief plant model description

The general plant design and structure have been described in great detail in a previous paper [10]. It consists of a simple fixed-bed gasification unit coupled to an anaerobic digester (AD) tank. While gasification as the substochiometrical oxidation of dry biomass such as wood chips or straw is a thermochemical process and generates a producer gas of mainly H_2, CO, CO_2 and N_2, AD as a biochemical process employs bacteria strains that digest wet biomass such as manure or vegetable waste and produces a biogas mixture of CH_4 and CO_2. Both producer gas and biogas are then used as a fuel for a microturbine (MT) as the power-generating unit of the plant, and fuel storages are used to enable plant flexibility and to avoid the necessity of electric storage. Most renewable power plants use extensive combined heat and power (CHP) technology in order to use process heat externally, for example for district heating. While this approach is certainly favourable as long as high heat loads exist, in general, most CHP plants lack an economic heat usage. Instead of using process heat for external heat loads, this design hence focuses on a high level of internal heat usage by recycling the main heat streams within the process, which leads to high overall efficiency levels. The plant process flowsheet with its main units is shown in Figure 1.

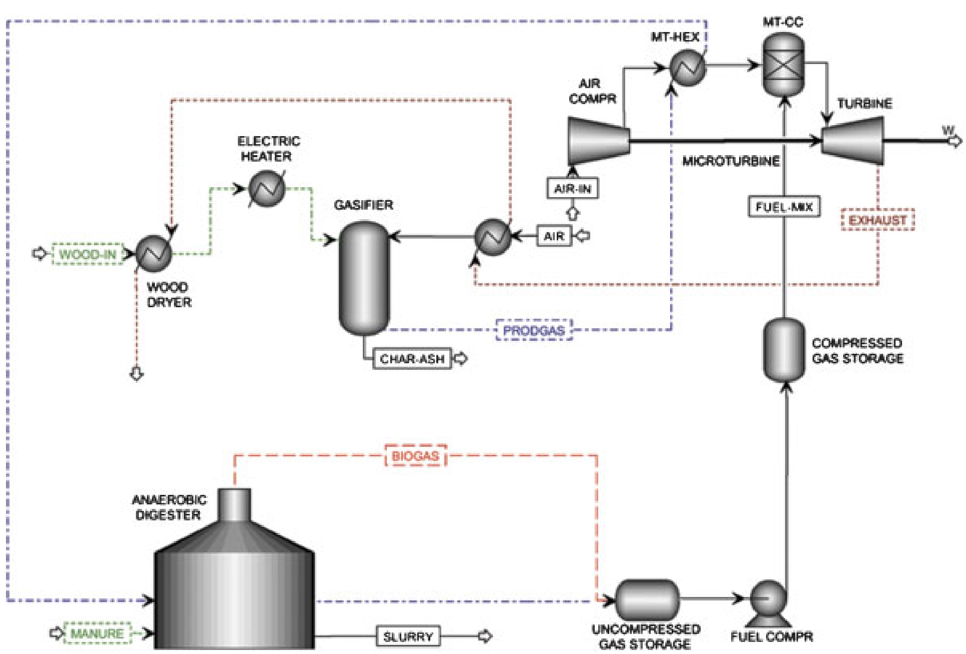

Figure 1. Combined feedstock micro-scale biomass generation plant design.

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Based on feasibility and scaling studies undertaken, it was found that this design could be scaled down to around 72 kW net base turbine power output. Considering the power amount necessary to drive the fuel compressor, this compares to a net base power output of around 58–60 kW. This minimum scale case is used as the base case for the simulations in this paper, and the feedstock input necessary to generate this power level is $112.5\,\mathrm{kg\,h^{-1}}$ of wet wood and $11\,000\,\mathrm{kg\,day^{-1}}$ of manure.

In a second step, this plant design was modelled in detail by employing standard chemical engineering software. All single units of the plant are well-known chemical and/or mechanical processes, and the model set-up is based on conservatively chosen parameters that have been validated against operational plants and the available literature. The plant model provides realistic and feasible results that represent the actual plant operation. The model description as well as the feasibility study results and the underlying mathematical and chemical models were published previously in this journal [11], and this model will be used for the operational studies described in this paper.

Load profile data description

When providing a remote area of farmhouses and adjacent domestic buildings with electricity independent from the grid, a main issue that needs to be addressed is how to facilitate the security of supply. Power demand fluctuates significantly over the course of the day and depends on numerous parameters such as season, location, outside temperature, etc. To be able to analyse whether the plant can cope with such demand, it is essential to use realistic demand data for simulations.

The plant is designed to provide electricity to a remote group of domestic customers, such as a small village. Therefore, it has to accommodate the actual load profile of such a group of houses. The load profile of a single dwelling can be described as a very low constant load combined with a random aggregation of very high power spikes. This follows from the fact that in individual households electrical appliances are the main power consumer. Those appliances cause the high power spikes on an intermittent basis: they are switched on and off, but without giving prior notice and without following a fixed pattern. It is therefore impossible to exactly forecast an individual load profile and the timing of its power spikes [12].

For a group of, for example 50, dwellings, the resulting load profile, however, strongly differs from simply adding 50 individual household load profiles. The exact timing of power spikes in an individual load profile is random and cannot be forecasted, but two individual households have two different timelines of power spikes. Again, this follows from statistics and from the fact that no two households have exactly the same power demand patterns. While at one second of time one household might draw its maximum power, another household might not need any power at all, and vice versa at the next second [12].

The result of this behaviour is that the larger the group of houses is, the smoother or more flattened the resulting load profile will be. While it is nearly impossible to forecast the power spikes of an individual household, it becomes more and more predictable for a rising number of dwellings. This is the reason that the plant used for the studies in this paper is designed to provide a group of houses with ongoing power, and not an individual dwelling: for groups of around 50–100 dwellings, the resulting load profile can be deemed as sufficiently flattened to be used for operational analyses [12].

Obtaining useful and detailed domestic load data is, however, very difficult. Restrictions on publication of load data exist as they are classified as proprietary by the utilities who hold them. Openly accessible load data is rare. A source deemed as both usable for the feasibility and simulation studies to be undertaken, and appropriate in means of real underlying data has been the publication of residential load profiles from the 'IEA/ECBCS Annex 42 Subtask A' research project [13].

These data provides the average 5-minute interval load demands (in Watt) based on a group of 69 residential UK dwellings, which were monitored between 2002 and 2005. This means that for every 5 min, a data point provides the average power demand drawn during this period by all the

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houses, divided by the number of houses in the group. The data sets are exclusive of space heating and consist of pure electricity demand. The measuring was undertaken during a 2-year period, and flats, town houses as well as semi-detached houses were included in the group.

These data are presented on a 1-day time basis and are differentiated by weekday/weekend and season. Three seasons were determined: winter (December–February), summer (June–August) and two shoulder seasons covering the remaining months of the year.

As can be expected, significant load level differences for the three seasons exist in the data sets for both weekdays and weekends, which is shown in Figure 2.

During the weekdays, two main peaks occur, which correlate with the working time of dwelling inhabitants. Night-time demand for electricity is lower than the day-time demand. In contrast to that, a shifted demand pattern occurs on weekend days, and a less distinct morning peak can be found. A relatively steady increase in the demand for electricity from the morning to the evening levels can be seen, and again the night-time demand is significantly below the day-time demand. These trends were expected and are well known in load profiling research; therefore, they indicate the usability of the data.

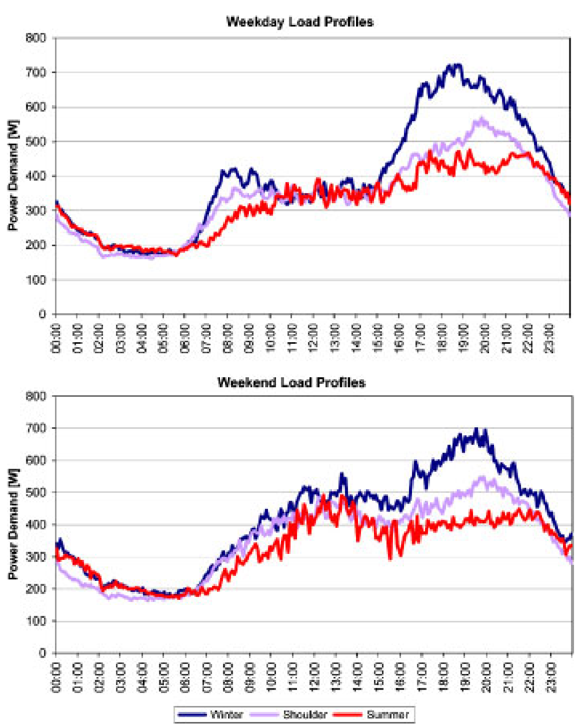

Figure 2. Seasonal household load profiles.

Discussing seasonal differences, the power demand is considerably higher in winter times than during the summer, especially during weekdays. While the intra-day patterns remain on a comparable basis within the seasons, their absolute level changes significantly. However, this result also has to be expected, as lighting demand or use of cookers increases during the cold seasons.

The data were collected between 2002 and 2005, thus a comparison with the current demand levels is necessary. Current absolute domestic electricity demand might be on a different level than provided in the source files; however, general patterns will remain the same. The average U.K. domestic electricity consumption for example has risen by 2.0% between 2002 and 2005, and fallen by 1.5% between 2005 and 2007 [14]. The focus of this paper, however, is to analyse the ability of the plant to cope with load patterns and fluctuations. As the general demand patterns that the data represent are still valid, it was decided to use the initial load data for the research and investigations to be undertaken, without manipulating it. Further work will include obtaining more recent load profiles that will enable to further validate this assumption.

A final evaluation was necessary to find a fitting number of houses that the power plant will provide with power. The plant size discussed above defines the minimum border of feasible scale and it was therefore decided to choose a demand pattern level that fits this scale. The original load profiles at each time interval provided the average power drawn by the whole group, divided by the number of dwellings. They were thus the proportionate per-dwelling load profile. For this study they were multiplied by a factor representing the number of dwellings to obtain the whole group's load profile. Evaluating the total net base power output levels and including suitable buffers for power increases, this multiplier was chosen as 120, which means that the load patterns in this study are set for a representative group of 120 dwellings.

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SIMULATION RESULTS AND DISCUSSION

Simulation set-up

In order to consistently and reliably match the demand, several power generation algorithms have been evaluated. On the one hand, generation needs to be at least at a level of the demand, and this becomes critical as demand can change significantly within short periods of time, hence a buffer needs to be implemented to cover instantaneous demand increases. On the other hand it is necessary to minimize generation in order to use resources effectively and to not generate significantly above the demand.

A number of power steps were developed for the generation plant to meet the demand. In order to allow smooth plant operation, it was analysed which operation pattern provides a combination of sufficient power output and acceptable excess power amounts. A minimum power output of 50% of the nominal turbine power was chosen, as this level has been mentioned as the minimum level at which MT generation can still be achieved in an effective and stable manner [15].

Based on the maximum expected demand and including a sufficient buffer for increasing demand, a nominal power level of 100 kW was established, which in turn means that the minimum power output will be 50 kW. These levels also correlate well with available MT technology [16–18].

The area between those two boundaries can be divided into a discretionary amount of intermediate power steps; however, the more the steps, the more often will the turbine need to be adjusted. Each plant adjustment will influence the stability and will require some time; hence, there will be a trade-off between the number of steps and their impacts on the operation stability. Additionally, the MT as the generation unit of the plant needs around 20–30 s to adjust to a new power level [19], thus infinitesimal power adjustment steps are not realistic.

By analysing and minimizing the offset power and using sufficient buffers, it has been found that three steps, at 65, 75 and 85 kW, provide an energy efficient and reliable operation pattern.

Before running the load patterns against this generation profile, it was finally checked whether the generation steps are feasible and how they impact the plant operation.

Generation step analysis

Both conversion parts of the plant need to be operated on a constant and continuous level to enable the AD processes and to maintain the gasifier temperature distribution. This however means that a certain amount of producer gas and biogas will be produced continuously.

The plant is using heat streams within its own processes, hence it is necessary to understand the impact on the plant when adopting several power output levels while keeping the conversion rates constant.

The output power of the MT depends on the amount of fuel gas, which is fed into the turbine. As the MT air intake is calculated on the basis of the fuel gas amount, this will change accordingly when adopting different power steps. This mainly impacts the MT heat exchanger, which uses the producer gas exhaust heat stream. An increase of air intake in the air compressor will mean that the heat exchanger will also be operated on a higher air mass stream. This effect is shown in Figure 3, which depicts the MT air intake amount as a function of its power output.

As the heat exchanger has a set geometry that will not change when more air is flowing through it, the amount of heat to be exchanged between the air stream and the producer gas stream will remain relatively constant. This however means for a higher air stream that the air outlet temperature, which is the temperature after the MT heat

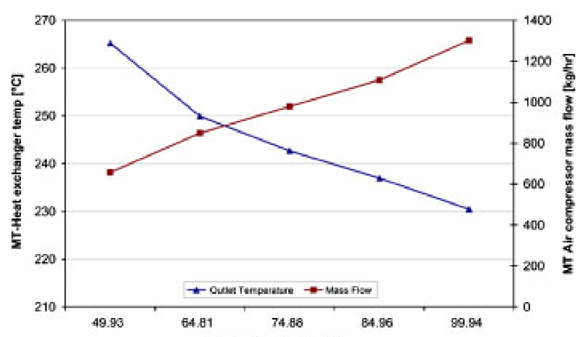

Figure 3. Power output variation impacts.

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exchanger, will change. This effect is also shown in Figure 3.

It can be seen that while the air mass stream increases with increasing power output, the hot air temperature decreases. However, the absolute level, from 265°C for half nominal load to 230°C at full load, does not influence the MT operation significantly, as the combustion chamber still provides sufficient levels of thermal energy for the exhaust gas to reach its maximum temperature level.

Other main plant parameters have also been checked and it was found that all parts of the plant can cope with changing the power output between half and full nominal power. Therefore, the MT operation on the chosen power steps is feasible, which means that this generation pattern can be used to try to match the demand.

Supply and demand analysis

For each of the three seasons that were discussed above, the daily demand patterns, rounded up to the next multiple of 5 kW, are shown in Figure 4. The *Winter Season* weekday and weekend profiles

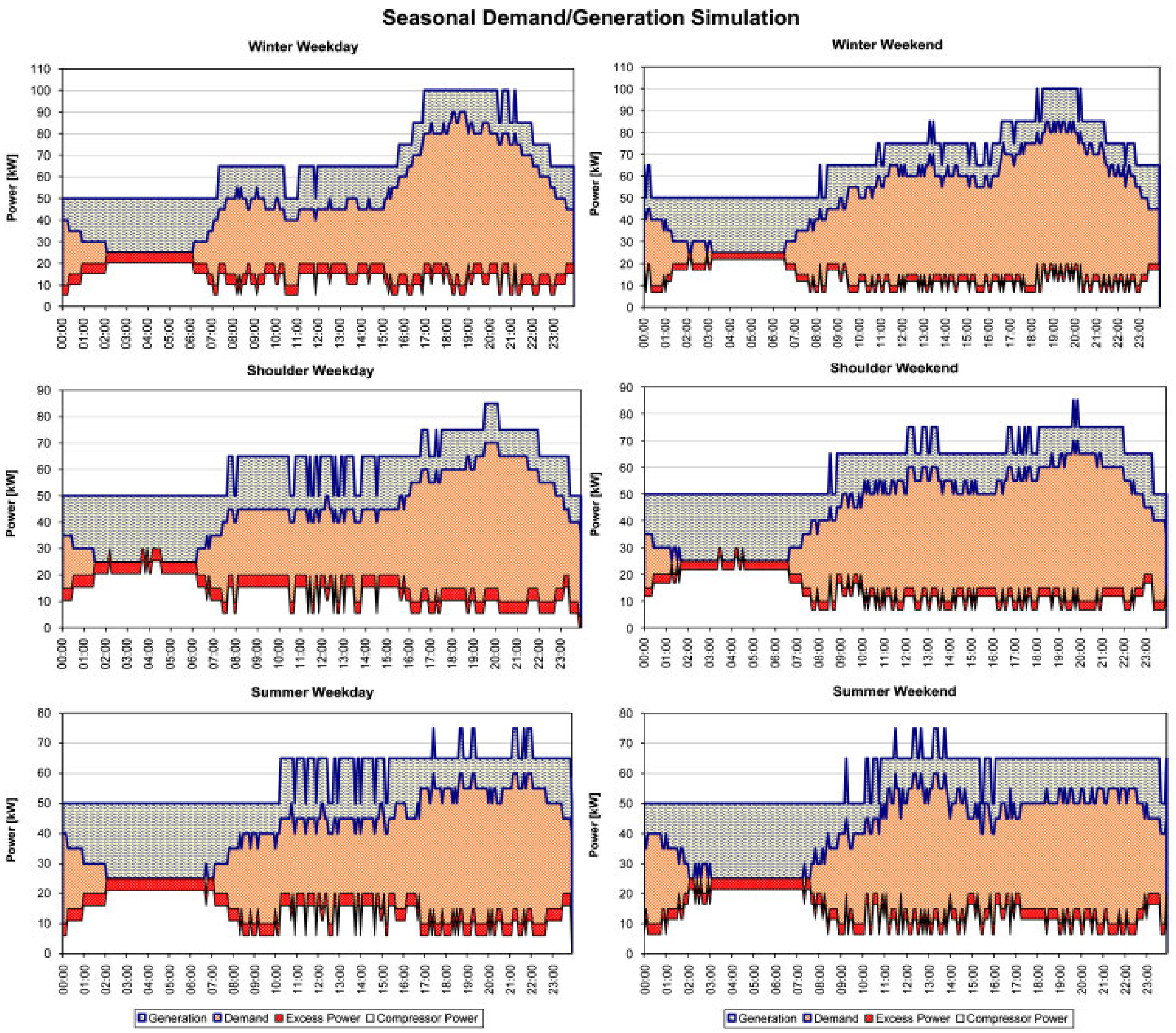

Figure 4. Seasonal demand and generation simulation results.

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are of the highest criticality with regard to their absolute level, thus they were analysed first.

Depending on the demand, the MT output was set to its respective power step of between 50 and 100 kW, using a control algorithm. As can be seen, the night-time demand falls sharply to levels of 25 kW, whereas the evening peaks reach values of up to 85 kW for the weekday and 80 kW for the weekend case. The difference in power generation between the demand curve and the generation curve can be defined as excess power and needs to be used within the process, as no electric storage is implemented. However, as the fuel compressor needs a certain amount of power to compress the producer gas/biogas mixture to the pressure level demanded by the MT, it acts as a compensator or sink of excess power.

The fuel gas conversion rates remain constant during the day, resulting in a constant output of uncompressed gas mixture, which needs to be compressed. However, there is no immediate need to compress this gas as long as storage is available, and this is why the fuel compressor can be employed as a tool to match supply and demand: it is operated on different power levels, depending on the amount of power available. As long as the whole gas amount is compressed during a longer overall period, such as one day, and as long as sufficient storage capacity is implemented, the MT will have sufficient compressed fuel gas to provide the demanded power levels. The variable compressor power level is shown in Figure 4, and it was calculated as the difference between generation and demand, including a buffer value called *Excess Power*, which is also shown in the graphs.

It can be seen that the power level of the compressor fluctuates between 5.3 and 20.3 kW for the weekday and between 7 and 22 kW for the weekend profiles. The resulting absolute value of the buffer indicates the criticality of the case, which means that a close match of demand and generation results in a low value of *Excess Power*. For both winter cases the buffer is between 3 and 5 kW, which provides sufficient levels for instantaneous power spikes, as will be discussed below.

Next, the demand patterns for the *Shoulder Season* weekday and weekend profiles were analysed. Compared to the winter profiles, a significant overall decrease in the power level can be seen. While the maximum demand reaches a level of 85 kW for the winter case, it only touches 70 kW for a maximum of 30 min during the shoulder season evening peaks. Simultaneously, the generation never reaches its full nominal power of 100 kW but stays below or at 85 kW for both weekday and weekend. This means that the total MT utilization factor decreases from 68% for the winter season cases to 61% for the shoulder season cases. However, as the main intention of the plant is to provide power continuously, a lower load factor has to be expected. This concept differs from conventional plant designs that aim for a large scale and high load factors, which mean flat output at nominal power, as they assume demand and supply can be matched by means of a grid connection.

The night-time demand during the shoulder season falls to 20–25 kW, which is also slightly lower than the respective winter demand. This means that the fuel compressor power range increases to 5–27 kW.

The *Excess Power* buffer level for the two shoulder season cases is also shown in Figure 4 and is slightly above the respective winter cases, which suggests that the shoulder season is less critical than the winter season.

Finally, the two *Summer Season* cases will be discussed. Again, the maximum demand level decreases and reaches a maximum value of 60 kW for the weekday evening peaks and for the weekend mid-day time. It is interesting to note that the summer season weekends are the only patterns where demand during the day is higher than evening demand, which might be related to a high demand for cooking and an otherwise low demand throughout the day.

However, apart from this change of the peak time, the demand profiles are similar, as the differences between daytime and evening are more distinct during the weekends than during the weekdays, and the night-time demands are significantly lower. For the summer period and especially for weekends, a nearly flat power demand can be seen, as the peak loses its distinction.

The generation pattern follows this lower demand and the MT power output reaches a maximum of 75 kW, which is one power step below the shoulder season and two steps below the nominal power. This results in a further slight decrease of the total MT utilization factor for the summer cases to 58%. The fuel compressor is operated in a range of 6–22 kW, which is also slightly lower than in the shoulder season. Again, the *Excess Power* buffer is slightly above its winter case value.

For an operation period of a whole calendar year, an average MT utilization factor can be calculated on the basis of allocating calendar days to the three seasons and to weekdays/weekends. This means that a calendar year consists of one winter season, one summer season and two shoulder seasons, with 65 weekdays and 26 weekend days per season. The overall average utilization factor for one calendar year can then be calculated as 62.2%, which as discussed above is an acceptable level considering the plant objective of continuous power supply.

Storage level and charge/discharge analysis

Both the MT output power and the fuel compressor power level are variable in order to level out the plant; therefore, gas storage becomes a necessity. Both conversion processes (gasification and AD) create a continuous flow of uncompressed gas, which, before being used as the MT fuel, needs to be compressed in the fuel compressor. The fuel compressor will be operating on several load levels as discussed in the sections above, so a certain amount of producer gas/biogas mixture will need to be stored in an uncompressed gas storage. Similarly, the amount of gas to be compressed does not necessarily equal the amount of compressed gas required by the MT, so the difference between those two amounts needs to be stored in a compressed gas storage.

To analyse sizing issues of both storages and to validate whether this operation pattern leads to an effective operation of the plant, it is necessary to evaluate the storage charge and discharge cycles as well as the absolute storage levels.

For each of the six demand profiles, the absolute levels of both the uncompressed gas storage (before the fuel compressor) and the compressed gas storage (after the fuel compressor) are shown in Figure 5. The scale of both graphs is m^3; however, it should be noted that the pressures are different: While the uncompressed gas storage has an atmospheric pressure, the compressed gas storage is maintained on a pressure of 5 bar to satisfy MT energy intake requirements.

In addition, Figure 5 also depicts the actual amounts of gas that are charged to or discharged from each of the two storages. The line named '*Uncomp Gas Dis-/Charge*' shows the volume of uncompressed gas mix being charged or discharged from the uncompressed storage. It equals the production amount minus the amount being compressed, depending on the current fuel compressor power. This means that it becomes positive when the fuel compressor compresses less gas than being produced, in which case the difference amount of gas is charged to the storage. It becomes negative when the fuel compressor compresses more gas than being produced, in which case the difference amount of gas is discharged from the storage. The scale again is volumetric with atmospheric pressure.

Simultaneously, the line named 'C*omp Gas Dis-/Charge*' shows the charge and discharge cycle for the compressed gas storage. Depending on the generation level of the MT, a certain amount of compressed fuel gas is needed. The line shows the difference between the amount of gas compressed by the fuel compressor and the amount needed by the MT. This means that it becomes negative when more compressed gas is needed by the MT than provided by the fuel compressor; this additional amount is then discharged from the storage. It becomes positive when the fuel compressor provides more gas than is needed by the turbine; this excess amount is then charged to the compressed gas storage.

In general, it can be seen that for the whole period of one day, the absolute storage levels of the uncompressed storage (the lines named '*Uncomp Gas Storage Level*') are balanced to zero. The total fuel compressor power over the whole day equals the amount of power that the compressor needs to compress the production volume, hence the storage start and end level must equal to zero. However, one can see that for all seasons, the night periods are the times of discharging uncompressed gas from the storage. This follows from the fact that the demand reaches its lowest levels during the night.

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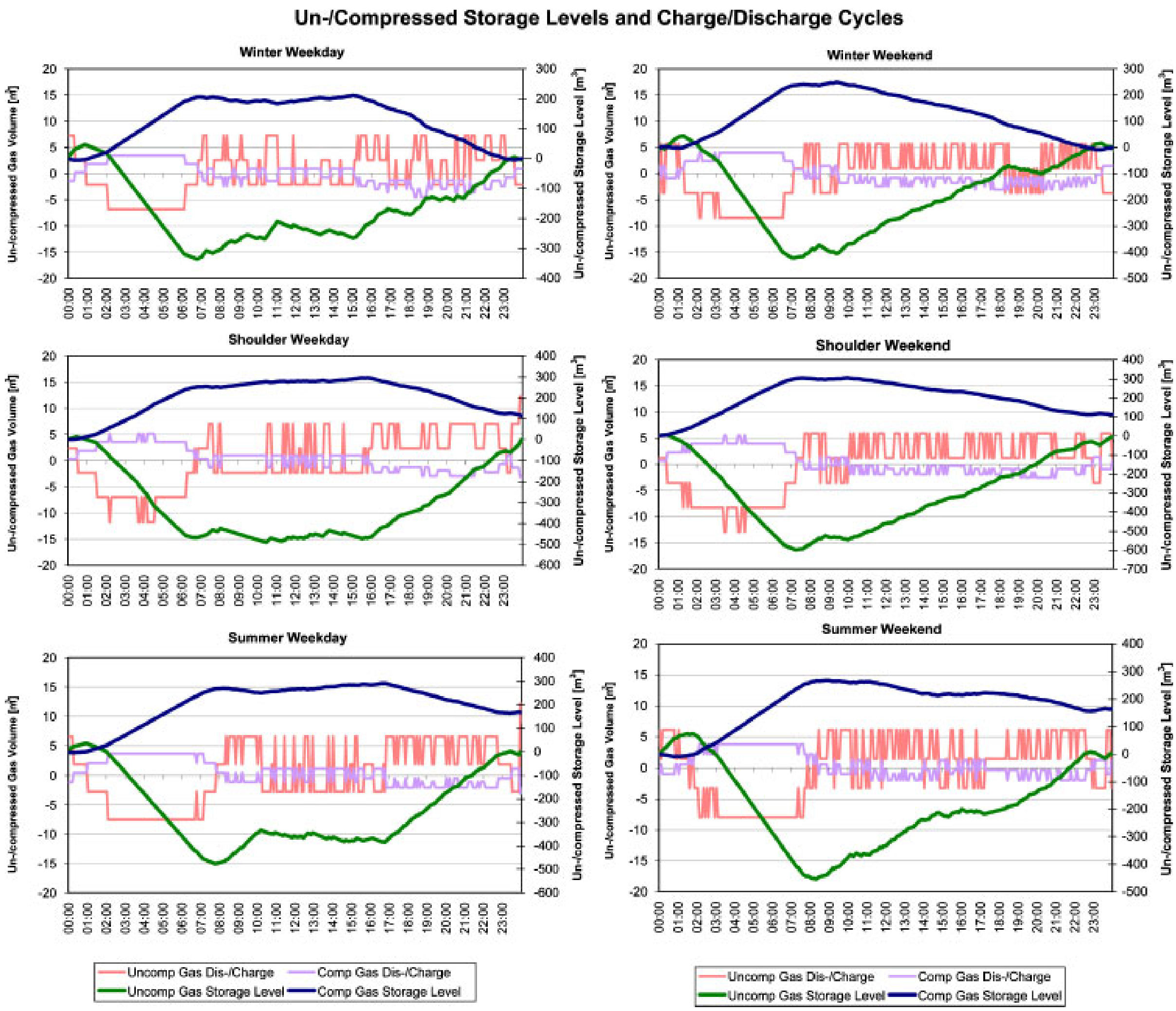

Figure 5. Storage levels and charge/discharge cycle.

As the MT is restricted to a minimum power output, the night times are the times of the highest fuel compressor power, which can be seen in Figure 4. Therefore, during the night the fuel compressor compresses more gas than is being produced, so it discharges from the storage. In comparison to that, during the day and evening peak times, the fuel compressor power is relatively low, as demand peaks and no power is 'left' for the compressor. So during those times, the fuel compressor compresses less gas than is being produced, and as a result the storage is charged with uncompressed gas.

The lowest absolute level of the uncompressed storage is the amount of gas that needs to be provided in order to ensure ongoing operation. It reaches its peak at a level of between 400–600 m^3 for the different seasons. Based on a gas production of 3528 $m^3 \, day^{-1}$ for the discussed base case, which results from the raw feedstock intake rates mentioned above, this means that between 12–18% of a daily production needs to be provided as storage. Both from the point of view of the absolute storage level, which influences the storage costs, and from its relative level, which impacts the operation of the system, this size can be deemed acceptable.

In comparison to that, the compressed gas storage levels (the lines named '*Comp Gas Storage Level*') show a different pattern. Again, in the winter case, by definition, the total daily gas production rate equals the amount of gas needed by the MT, so all gas compressed will be used by the turbine throughout the day. As night-time power levels are low, the MT needs less compressed gas than provided by the compressor, and the storage is charged. Simultaneously, during the times of high turbine generation, the storage is discharged.

However, the compressed storage will just level to zero for the winter cases, while for the shoulder and summer seasons, it does not return to being empty. This follows from the fact that during shoulder and summer seasons, the total power generated by the MT over the whole day is below the respective values for the winter season, as discussed above. Table I shows that for both winter cases, the generation patterns result in the same amount of $kWh\,d^{-1}$ of generation. Compared to that, for the shoulder and summer seasons, the generation patterns are lower due to lower demand. Simultaneously, the uncompressed fuel gas amount required to generate the calculated amount of power is lower for the shoulder and summer seasons than for the winter season. As the gas production rate stays constant at $3528\,m^3\,d^{-1}$, this results in more gas being produced than being needed by the turbine. The relative excess gas ratio amounts to 9.2–9.5% for the shoulder season and 13.6–13.8% for the summer season, respectively. The absolute excess gas amount mentioned in Table I equals the amount that is left in the compressed gas storage at the end of the 1-day period in Figure 5; however, it should be noted that Table I states uncompressed volumes, while Figure 5 shows the compressed volume.

The absolute peak levels for the compressed storage reach between 200–300 m^3 of compressed gas. Based on the daily production of gas and converting uncompressed into compressed volumes, the storage needs to be sized to around 17–26% of the daily production, which again is on an acceptable level.

Given the amount of excess gas produced during the shoulder and summer seasons, and using the allocation of calendar days to an operation period of a whole year as mentioned in the section above, the average yearly excess gas production amounts to 8.2% of the total gas production. Therefore, it could be beneficial to decrease the average gas production rate accordingly. However, a further decrease of the gas production rate will impact the streams within the plant design, as heat exchangers use hot gas streams such as the producer gas stream for preheating parts of the plant, as discussed before. Therefore, an alternative to adjusting the gas production rate would be to use this excessive gas mixture as a source for additional power necessary to pretreat feedstock. For example, the gasifier feedstock needs to be provided in a certain particle size, thus a wood chopper would be necessary, which can be operated in intervals by extra power generated from the 'excess fuel gas'. Another possible use of this gas could be as a safety buffer for demand increase or

Table I. Generation comparison and excess gas calculation.

	Generation [$kWh\,d^{-1}$]	Gas demand [$m^3\,d^{-1}$]	Excess gas [$m^3\,d^{-1}$]	Excess relative [%]
Winter				
weekday	1624	3528	—	—
weekend	1624	3528	—	—
Shoulder				
weekday	1470	3192	336	9.5
weekend	1475	3203	325	9.2
Summer				
weekday	1400	3041	487	13.8
weekend	1403	3047	481	13.6

for unplanned issues such as quality problems with the fuel gas.

Demand fluctuation analysis

A final investigation analyses the amount and occurrence of fluctuations within the daily profiles. As described earlier, the plant needs to be flexible enough to accommodate sudden load changes, as there will be no electricity storage available. Therefore, it is essential that the generation always exceeds demand so that a sufficient buffer for higher loads exists. The algorithms that were employed to set the level of generation are based on the actual load profile demand; however, they were checked against changes in the demand from one data point to another.

It first needs to be remembered that the load profiles provide data in 5-minute intervals, while a real load profile will change more often. In reality, the load demand of a group of dwellings will change continuously [12]. This means that however fine a scaling is applied for load profiles, it will never provide the actual load, but will instead always provide a number of average loads for each time interval chosen. The actual load changes, however, are the ones that the plant has to cope with, hence the analysis in this chapter first has to evaluate to what extend the data available is representative for the actual changes. A more transient analysis that investigates the short-time actual load changes will remain a part of further work as it requires actual real-time demand changes, which are not available yet. The authors are currently obtaining load profiles on a highly detailed basis (far less than one second) and once this data is available, a fully transient analysis can be undertaken.

To understand whether the load profiles available can be deemed appropriate to characterize real load profiles, their characteristics need to be analysed. It was discussed above that load changes of an individual dwelling do not follow a firm pattern, but are random, and that this random distribution results in a flattened and smoother load profile for a larger group of households. The sampling interval of 5 min can also be treated as random, because during the sampling period a random time was chosen as the starting time of the interval. As the load changes do not follow a pattern, the sampling intervals will not regularly coincide with the actual load changes. For each interval, the data provide the average amount of power drawn, and this means that each interval will contain a random amount of actual load changes, which fell within the sampling interval. When comparing one interval with another, the difference between the two average amounts of power is compared, and thus the difference of the two random amounts of load changes. This however means that the characteristics of the available 5-minute intervals will not be different from lower sampling intervals, as long as they still are of a size that includes a number of different load changes. It was mentioned above that even 1-second intervals will include a number of load changes, as load fluctuates continuously. Therefore, the available 5-minute intervals will be a valid approach to characterize and analyse the change of demand over time, which is what this study aims for.

It has been shown experimentally that load ramping of a MT can be achieved without major impacts on the frequency and voltage of the output power; however, it will take around 30 s to adjust to a new power output [19]. This implies that the MT will never be able to immediately follow the load, but that it will need time to adjust to a new power step. Hence, the algorithms to be implemented for following the load will have to include sufficient buffers to accommodate load changes within the time period of adjusting the MT. Therefore, an analysis of the absolute fluctuations to be expected from one data point to the next was undertaken. The absolute demand fluctuations from one data point to the following are shown in Figure 6 for the six available profiles.

In general, it can be stated that the most significant fluctuations occur during the day-time, while during the night only lower levels of demand change are seen. This pattern is similar throughout all seasons and does not vary significantly between weekdays and weekends, although the increase of fluctuations is slightly delayed to the later morning hours on weekends.

These findings, however, correspond to the average activity patterns of inhabited dwellings.

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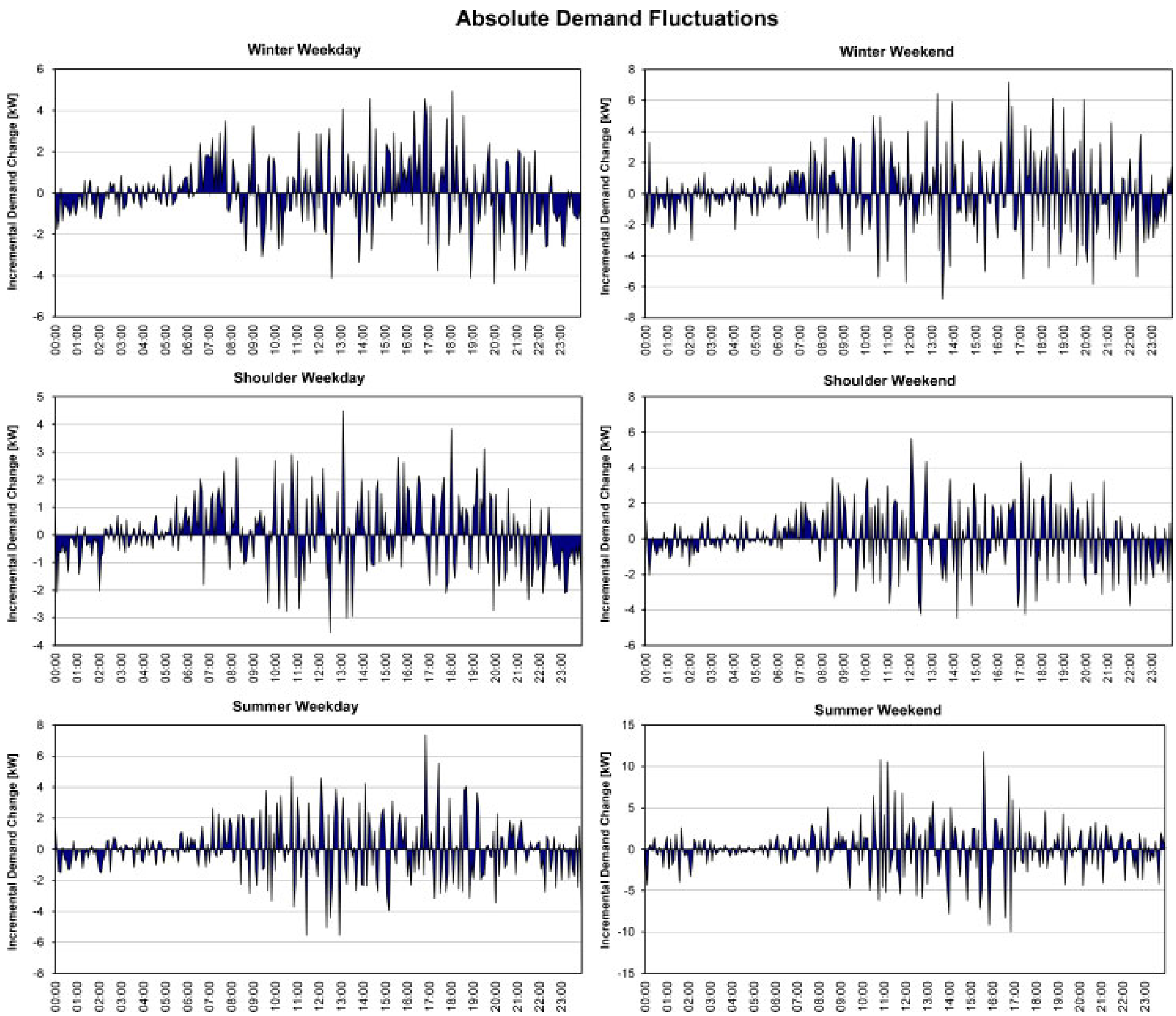

Figure 6. Absolute demand fluctuations.

During the night, comparably few appliances are switched on or off, so the demand is more stable than during the day-time or evening, where inhabitants use appliances intermittently.

Discussing the actual size of the fluctuations, it can be seen that for all profiles apart from the summer weekend profile, the peak fluctuations are below 8 kW. For the summer weekend case, they reach levels of above 10 kW, however, only on three (out of a total of 288) occasions. Table II provides the maximum absolute fluctuation as well as the average absolute fluctuation and their respective standard deviation values for the six cases.

Compared to demand increases, demand decreases can be treated with ease. Should the demand for power slump, then more power is available for the fuel compressor, which results in a higher fuel gas throughput. Therefore, the power decreases are of low criticality.

The plant, however, has to accommodate increases in demand by means of the buffers included in the calculation of the generation pattern. The buffers need to be of sufficient size, which means they need to be at least of the size of the fluctuations, and sufficient margins of safety need to be included as well.

Table II. Demand fluctuation analysis.

	Max. abs. fluctuation [kW]	Avg. abs. fluctuation [kW]	Standard deviation [kW]
Winter			
weekday	4.92	1.24	1.05
weekend	7.17	1.74	1.51
Shoulder			
weekday	4.49	0.92	0.79
weekend	5.62	1.26	1.08
Summer			
weekday	7.35	1.32	1.22
weekend	11.77	1.92	2.01

Table III. Safety margin analysis.

	Excess power [kW]	Min. comp. power [kW]	Margin of safety [%]
Winter			
weekday	4.72	5.27	203.3
weekend	3.02	6.98	139.5
Shoulder			
weekday	4.53	5.47	222.5
weekend	3.26	6.74	177.9
Summer			
weekday	4.01	5.99	136.0
weekend	3.54	6.46	85.0

As discussed previously, the buffers consist of a variable part and a fixed part. The variable part is the difference between the actual demand and the round-up value to the next multiple of 5 kW. The size of this will thus always be below 5 kW; however, it is difficult to evaluate what actual size this buffer will have in general. Analysing the size of the buffer for the available profiles results in levels between nearly 0 and nearly 5, which is the whole available buffer range. Averages are within a band of 2.3 and 2.7; however, the standard deviation, with between 1.3 and 1.6, is relatively high. Additionally, due to the way of measuring the load, the buffer size will always be of random origin, as instantaneous actual demand changes do not fall together with measurements at fixed time intervals. Therefore, this buffer cannot be allocated a safe value for this analysis and will be excluded, although knowing that additional safety exists, but cannot be guaranteed.

The fixed size buffer is the difference between generation and rounded demand. It consists of two parts, of which one will always be available: First, the amount of what has been called *Excess Power* in Figure 4, which is the difference between generation and demand plus fuel compressor power. This buffer will always be available for accommodating fluctuations. The remainder of it will have to be used up by the plant's power sink, the electric heater, as no power can be stored. As discussed in [11], the electric heater can compensate up to 6.25 kW of power on a continuous basis, and even higher power levels as long as they occur intermittently. The second part of the fixed size buffer is the actual amount of power dedicated to the fuel compressor. Although the fuel compressor should be operated on this power, in the event of a high-level power spike, the plant will override this allocation and use the fuel compressor power to meet the demand. As this can be done by automatic control, it will provide sufficient power to the demand as long as the fuel compressor can be switched to a lower power level. The level of the *Excess Power* as well as the minimum power available for the fuel compressor are stated in Table III; additionally, the margin of safety is given as a percentage of the respective maximum absolute fluctuation (being 100%) of Table II.

Analysing the level of both the *Excess Power* and the amount of power dedicated for the fuel compressor, it can be seen that there will always be sufficient power available to accommodate the demand fluctuations. Apart from the summer weekend case, the maximum increase in the power demand from one data point to the next can always be met by the buffer, and as the margins of safety are all above 100%, it can be concluded that even the highest peaks can be accommodated with ease.

For the summer weekend case, the margin of safety is below 100% due to the three extremely high single peaks. If those three peaks were excluded from the data set, a margin of safety for the summer weekend case of 101% would be the result, which means that the remaining peaks fall within the level, which can be accommodated.

It should at this point be mentioned again that with a rising group of dwellings the resulting load profile flattens and smoothens. The original load

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profiles were obtained from 69 dwellings [13]; however, the multiplier used for this study created a group of 120 dwellings. Therefore, the flattening effect of increasing the group size from 69 to 120 was not included. Increasing the number of households in a group has a significant impact on the absolute level of power spikes in a way that the larger the group, the lower the relative value of its power spikes. This however means that for a larger group of dwellings, the amount of the highest power spikes will be smaller, and for the given group of 120 houses the highest relative peaks would also be below the level of a group of 69 houses. The three peaks in the summer weekend profile can therefore be accepted as exceptional peaks that result from the methodology. The values for the other cases show that significant margins of safety were implemented even on the basis of the highest available peaks; therefore, it would be unreasonable to conclude that those three peaks would also need to be accommodated. A very conservative approach has been chosen and the authors are confident that this exclusion can be accepted.

It can therefore be concluded that the plant is able to cope with absolute and relative demand fluctuations with ease, and that it can reliably provide power on an ongoing basis. Additional work however needs to investigate in more detail the transient behaviour of the power system based on actual real-time demand changes that occur, in order to provide further proof that the fluctuations of the profiles used in this study are realistic.

CONCLUSIONS AND FURTHER WORK

A novel micro-scale biomass plant has been designed to provide reliable renewable energy to customers in remote regions. While the current focus of biomass power generation is on large-scale plants that provide flat base-load electricity and use an ageing and costly grid infrastructure, this design uses locally available feedstock to generate power at the point of demand. Instead of optimizing the plant for a flat base power output, this design accepts lower overall load factors and excess power generation and instead focuses on the ongoing power provision and flexibility of operation. It can thus provide decentralized reliable energy and help remote areas to gain energy self-sufficiency.

While the plant description and modelling was covered in a previous paper in this journal, in this paper it was shown that the plant is able to meet the local domestic demand for power on an ongoing basis. Flexible power generation was achieved using domestic load profiles. For a group of 120 dwellings of domestic use, the daily demand ranges within a minimum of 25 kW to up to 85 kW for a winter weekday, compared to 25–60 kW for the summer weekend. This very high level of demand variation can be accommodated by the plant with ease. By applying different generation steps between half load and full nominal load, the output can be adjusted to the demand. By including sufficient load buffers, the plant can cope with those load changes, and it can still be operated in a smooth and stable manner. It has thus been proven that the plant is able to provide the needed amount of power on a 24/7 basis during all seasons.

Apart from the flexibility of operation, the plant provides another unique design feature: electrical storage such as batteries was avoided, which provides significant benefits with regards to maintenance, economic and ecological impact. Fuel gas will be stored to provide capacity for adjusting the power if necessary, which is a more suitable alternative to electrical storage. The sizing of the gas storages was investigated and found to be on acceptable levels: to provide sufficient storage for the plant, absolute maximum storage levels will not exceed 20 or 30% of the daily gas production for the uncompressed or compressed gas storage, respectively. Those storage volumes can be implemented with ease and result, together with the technology applied for the remaining plant units, in a conveniently sized local power plant.

The ability of the plant to accommodate instantaneous load changes was also evaluated in this paper. Especially for domestic power demand, intermittent appliance usage results in power spikes and slumps, which becomes critical for local generation without grid connection, as those fluctuations need to be met by sufficient generation.

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The plant design can be adjusted quickly to accommodate higher loads by switching power from the fuel compressor and electric heater, which act as the power sinks of the system, to the demand, and vice versa in case of power slumps. The plant can thus meet the demand continuously without power cuts or demand-side management, but by generating the above demand and utilizing this 'excess' power within its own processes for higher efficiency.

By using realistic load profiles of a fitting size, the criticality of ongoing power supply for highly changing loads was addressed and resolved. Further simulations will be focused on a detailed transient analysis. Additionally, different load patterns such as farm-scale or industrial load profiles will be analysed to prove whether this design can also be employed for such customers, and an economic analysis of the plant will be undertaken to compare this novel form of rural electrification to a conventional grid connection.

It has been shown in this paper that the novel combined feedstock micro-scale biomass generation plant design is able to supply ongoing reliable power to remote domestic demand. This design marks a milestone in the field of biomass-to-power applications research and shows an alternative to often-preferred centralized large-scale power plants.

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Modelling and simulation of a novel micro-scale combined feedstock biomass generation plant for grid-independent power supply

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SUMMARY

Remotely located and sparsely populated areas often do not have access to an efficient grid connection for electricity supply. However, plenty of biomass is normally available in such areas. Instead of employing island solutions such as diesel generators or large battery stacks with severe impacts on both the environment and economics of rural electrification, a micro-scale biomass plant using locally available feedstock to produce electricity and/or heat is an efficient way of not only providing those areas with competitive and reliable electricity, but also a step towards energy self-sufficiency for a large share of areas worldwide.

Both wet and dry feedstock are usually available in remote areas, therefore a novel plant design combining thermochemical and biochemical treatment has been developed. The system consists of a small-scale downdraft gasifier and an anaerobic digester unit, both coupled to a gas storage system and a microturbine as the generation unit. This combined feedstock design is suitable to provide electricity down to a level of around 50 kWe, which suits a remote village or a large farm.

This paper covers the modelling of the plant design in chemical engineering simulation software. Additionally, feasibility studies and results obtained from operation simulations are described and show that such a system is a feasible and an economic solution for remote power supply. Copyright © 2009 John Wiley & Sons, Ltd.

KEY WORDS: micro-scale applications; decentralized electricity generation; stand-alone-systems; gasification; anaerobic digestion; microturbine; biomass

1. INTRODUCTION

When considering renewable energy systems, biomass-based power supply has a number of advantages over other renewable energy sources, such as no intermittency, high regional availability and employment of well-known chemical process designs. Therefore, biomass-based power generation and supply could provide a significant share of electricity to most regions in the world and be a milestone in achieving energy self-sufficiency. However, recent activity in biomass-related system design and operation focuses on optimising

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large-scale plants for a base and flat power supply [1–3], and a grid connection is expected to be available for exporting excessive and importing shortfall amounts of power to meet domestic demands.

Although this approach may be suitable in developed countries with well-operated transmission and distribution grid systems, a stable grid connection is not available everywhere. Especially in remote regions, only a weak or no grid connection at all can be provided, which means that most currently available biomass plant designs fail, as they are unable to cope with volatility and fluctuating power demand. Rural electrification thus currently means decentralized plants being operated on flat power output for only a number of hours per day, and the demand is expected to follow this operation pattern [4–6].

However, as remote locations normally provide high regional availability of biomass, a continuously operated biomass plant with flexible power output would provide significant benefits and improvements in areas where otherwise only intermittent and fossil-fuel-dependent power can be provided.

Issues to be investigated for such a system include design aspects as well as costs, flexibility and feasibility of operation and scaling limitations. In order to gain understanding of the processes and operation of such a system, this paper provides a detailed model of a micro-scale biomass-based generation plant. The underlying design principles were specifically developed in a way that the plant can be operated in remote regions and does not depend on a grid connection. As this model will be used as a precursor of a prototype plant to be set up, a detailed description is provided to ensure that the simulations provide a realistic and suitable model. In addition to that, feasibility simulations were undertaken and operation results are provided in this paper. It will be shown that such a plant provides a feasible and a very interesting option for rural electrification.

2. PLANT DESCRIPTION

When developing a micro-scale plant for energy provision in remote regions, special emphasis needs to be laid on fuel that is already available. Considering biomass, several advantages such as high regional availability, no intermittency and the ease of storing feedstock can be combined.

However, most current biomass plants focus on using only a share of available biomass: Plants use either thermochemical treatment for dry biomass or biochemical treatment for wet biomass. Thermochemical treatment, such as pyrolysis and gasification, requires wood chips, straw or energy crops, whereas biochemical treatment such as anaerobic digestion or fermentation is suitable for livestock manure or vegetable waste.

Remote regions that are sparsely populated and undertake agricultural activities have both wet and dry feedstock available. Thus, a combination of wet and dry biomass treatment processes seems very beneficial in two ways: all available feedstock and internal process heat streams can be used very efficiently. However, such combined feedstock plants have not been set up so far.

The authors have recently proposed a novel combined feedstock biomass power plant design for both thermochemical and biochemical treatment [7, 8]. Its main parts and design aspects have been described in detail in the aforementioned publications, however the plant consists of a simple gasification system for dry biomass such as wood chips and an anaerobic digestion reactor for wet biomass such as livestock manure. A microturbine forms the power generation part of the plant, and the whole design can be scaled down to power levels of 50 kWe and hence provides a fitting size for remote villages.

Most existing power plants lack efficiency due to unused excess heat [1,9–11], therefore a focus has been laid on a high internal use of heat streams. This not only increases the overall system efficiency, but also provides the option to scale each sub-unit according to its heat input and output. An optimal scaling ratio of all single units will then result in an optimized overall plant system.

Additionally, the plant design was chosen to enable very flexible operation in order to meet high fluctuations that have to be expected when using the plant as a sole generator in a power island consisting of rural domestic and farm housing.

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Another major challenge was choosing technology that provides long maintenance cycles to enable the design to be operated in remote areas without skilled personnel.

Finally, a focus was laid on simple conversion technologies in order to minimize the overall system cost. As both wet and dry feedstock are utilized, the plant uses more technology than single-feedstock systems. However, the main focus of this plant is the ongoing supply of reliable and decentralized power, therefore system costs are not the only factor for a decision. For example, a conventional grid-connection cost analysis would have to include transmission losses as well as grid maintenance and setup costs, which would not occur in the case of using this system. A detailed economic analysis of the plant would go beyond the scope of this paper, however it will be addressed in future work.

The general design of the plant and its main units are shown in the system process chart in Figure 1.

3. SIMULATION METHODOLOGY

A detailed model of this plant has been set up in order to check its feasibility and provide operational results as well as ways of optimization of the plant. The plant was modelled in the Aspen chemical simulation environment using a number of chemical models for each of the main parts of this plant. This software was chosen because of its frequency of use and due to it provides a large number of power and chemical engineering models that are beneficial for creating a realistic model. Using a proven industrial process engineering software package to model reaction kinetics, mass and energy transfer and the like enables the use of a large set of standard models and properties. As

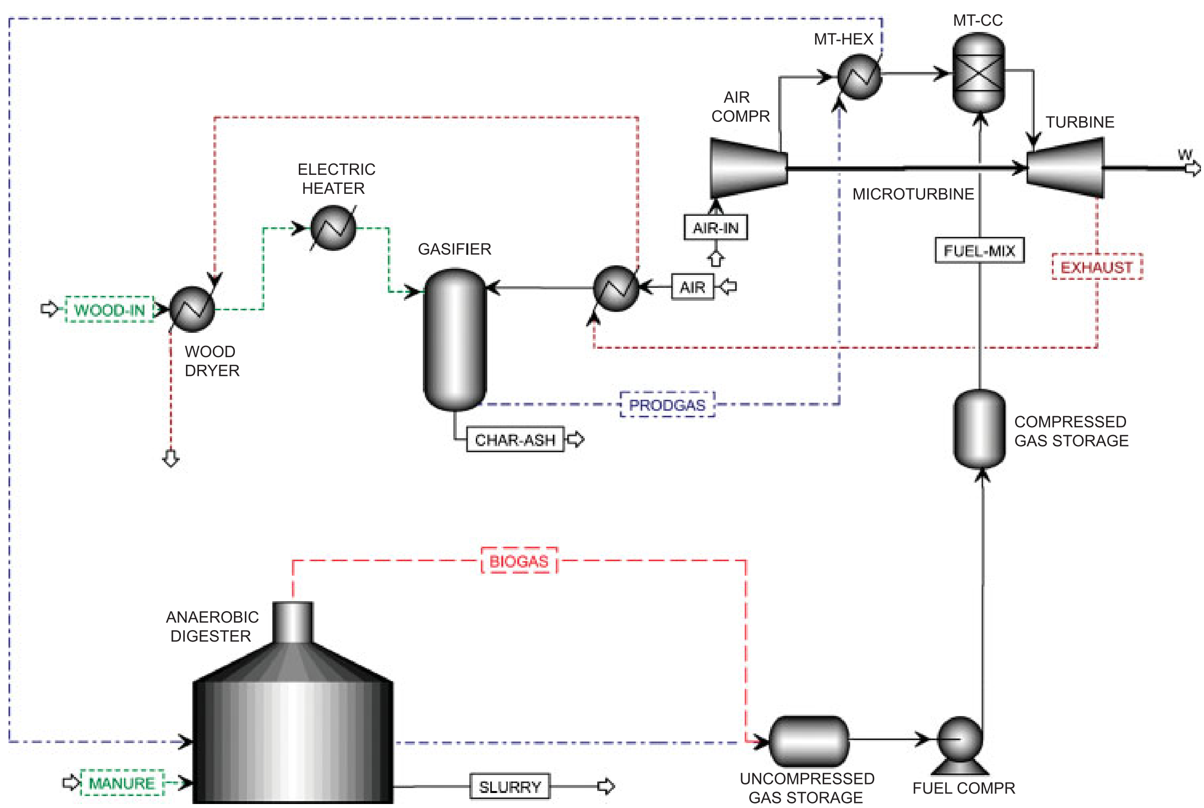

Figure 1. Combined feedstock biomass plant design.

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Aspen also provides a high level of adjustment options by means of parameterization, the level of detail can be chosen easily.

The modelling was undertaken in Aspen Plus, which provides and computes steady-state process models. Both biomass conversion technologies adopted in this plant need to be operated in a continuous and steady manner, in order to obtain efficiency and consistent fuel gas qualities. Therefore, a steady-state modelling of those processes is coherent and has also been recommended in literature [12]. The generation part of the plant will have to cope with fluctuating loads as it will be the single power source of the system. It therefore will need to change its output power level to accommodate differences in demand over time. However, it is known that microturbine operation also requires a certain amount of steadiness, as the turbine needs around 20–30 s to adopt a new output power level [13]. The plant design thus arranges for the microturbine to be operated on a number of power steps, and the power sinks will accommodate fluctuations in-between those power steps. The microturbine dynamic operation can therefore be modelled as a sequence of steady-state operations on different power levels. Additionally, the Aspen software package provides a dynamic simulation software, Aspen Dynamics, which can be employed for analysing the transient steps when the turbine power level is changed.

An overview of the complete plant model in Aspen Plus is shown in Figure 2, and each main subsection is described in detail afterwards.

3.1. Gasifier

The gasifier has been modelled using a two-step approach, as shown in Figure 3.

Biomass cannot be modelled within Aspen as a normal component stream as it is not a conventional chemical substance, but a homogenous mix of a large number of different organic molecules. Therefore, the dry biomass feedstock in the form of wood chips is modelled as a non-conventional material stream using proximate and ultimate analysis values from literature such as [14–18], which results in the following pseudo-formula:

$$CH_{1.3}O_{0.66}N_{0.006}S_{0.0001} \qquad (1)\leftarrow$$

Additionally, an ash content is modelled based on the literature mentioned above. Those properties vary very little between different wood feedstocks and can therefore be assumed to be constant.

In the first step, biomass chips are decomposed into their main compository elements, as expressed by the following overall formula:

$$CHONS \rightarrow C + H_2 + O_2 + N_2 + S \qquad (2)\leftarrow$$

The stoichiometric decomposition is accommodated in the *DECOMP* simulation block. The resulting elementary stream *ELEMENTS* is then converted into a producer gas mixture in the *GASIFIER* block. Air is used as the gasification medium, and first passes a heat exchanger that uses the turbine exhaust heat stream to preheat the air. A hot inlet stream/cold outlet stream temperature difference approach of 10 K has been implemented in order to use excessive thermal energy from the exhaust gas stream, and an air/fuel ratio of 1.5 based on dry, ash-free biomass has been implemented, which has been mentioned as a common value in literature and proven to provide best results [17]. This preheated airstream, together with the decomposed biomass stream, is converted into producer gas, a gas mainly consisting of nitrogen, carbon monoxide, hydrogen and carbon dioxide. For this conversion, an *RGIBBS* reactor type is used, which calculates the product composition based on the minimization of Gibb's free energy [19]. Gibb's free energy of a system is a thermodynamic potential that measures the maximum amount of non-expansion work available from a system. It can be described as:

$$G = H - TS \qquad (3)\leftarrow$$

For a system where changes such as reactions occur, a negative difference in Gibb's free energy between two states 1 and 2—before and after the reaction—leads to a more stable, i.e. favourable, state of the system, and can be expressed as

$$\Delta G = G_2 - G_1 < 0 \qquad (4)\leftarrow$$

Thus, the minimization of Gibb's free energy approach results in the most thermodynamically favourable state of a system and therefore models chemical reactions.

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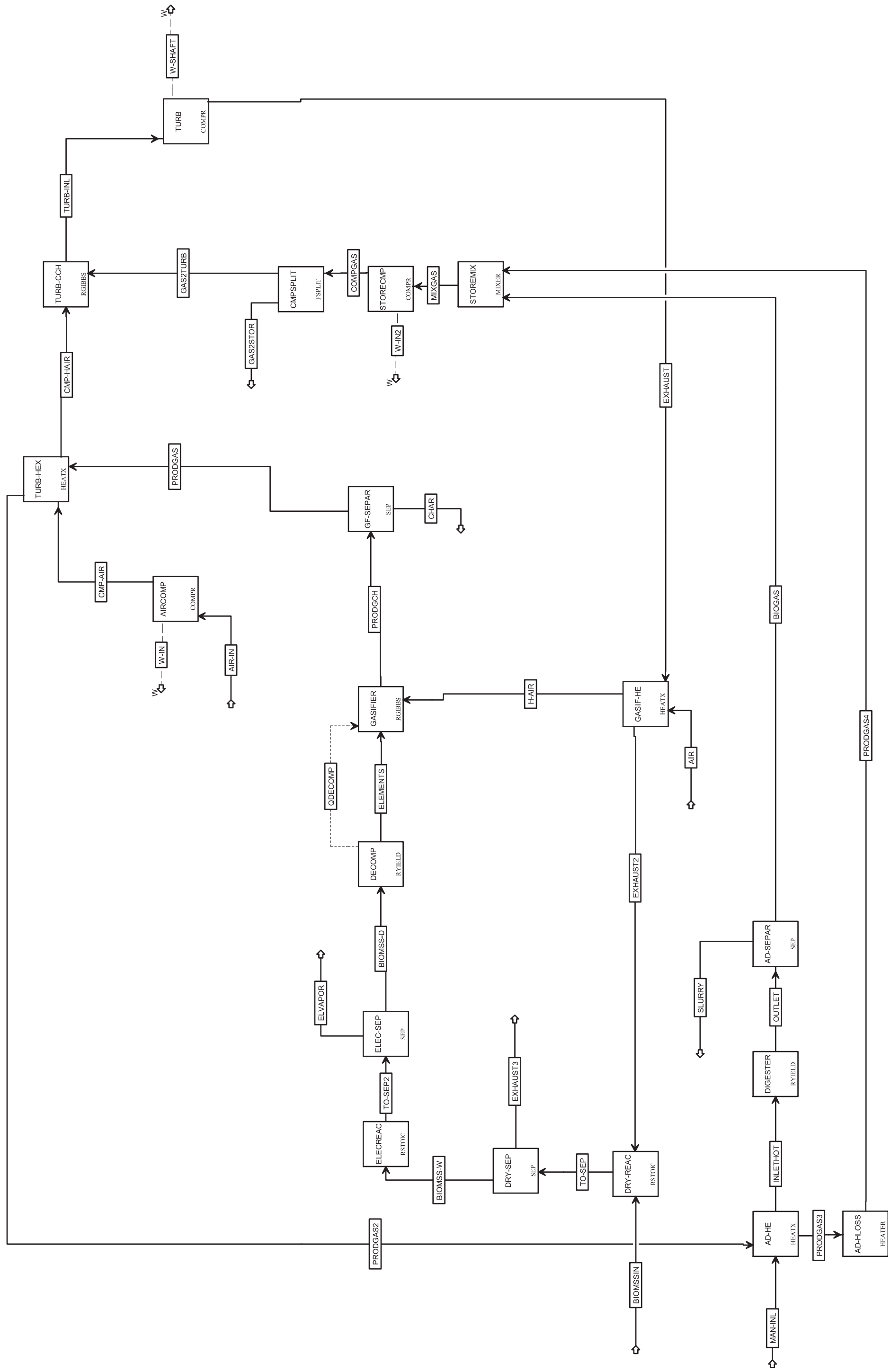

Figure 2. Plant model flowsheet.

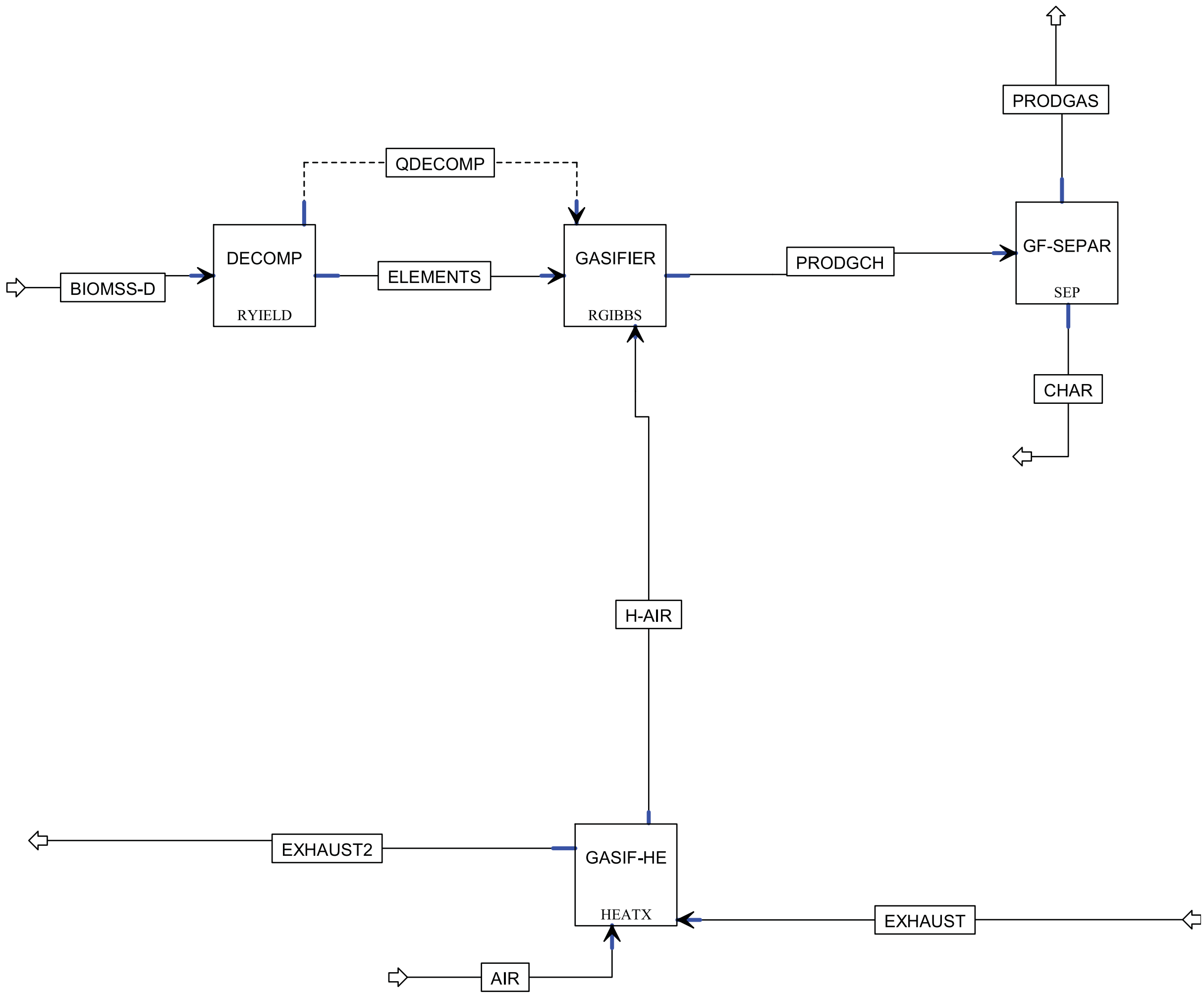

Figure 3. Gasifier model flowsheet.

An additional heat stream *QDECOMP* connects the decomposer block with the reactor block and carries the Gibb's free energy of formation difference between the biomass feedstock stream *BIOMSS-D* and the decomposed elementary stream *ELEMENTS*. The change of Gibb's free energy of any reaction is the change between Gibb's free energy of formation of the products and the reactants, as expressed by

$$\Delta G_r = \sum (n\Delta G_{\mathrm{f}})_{\mathrm{prod}} - \sum (n\Delta G_{\mathrm{f}})_{\mathrm{react}} \qquad (5)\leftarrow$$

By definition, Gibb's free energy of formation for all elements in their standard state is set to zero, so *QDECOMP* contains Gibb's free energy of formation of the biomass, which equals Gibb's free energy of the decomposition reaction, and is necessary for remaining energy balance between the two systems.

Setting up a gasifier with this model and assuming chemical equilibrium approaches has been declared an appropriate approach and provides realistic chemical properties of the resulting streams, especially for fixed-bed downdraft gasification systems [12,20,21].

After gasification reactions have taken place, a separator block *GF-SEPAR* is used to divert ash and unconverted biomass in the form of coal (stream *CHAR*) from the producer gas stream *PRODGAS*. The char and ash stream can then be returned to the gasifier to release the energy contained in unconverted char, whereas the producer gas stream is connected to further downstream parts of the plant.

The authors are aware that one of the main obstacles of gasification technology at the moment is to obtain a clean producer gas stream, and tar residues and other impurities severely limit the application of especially small-scale gasifiers. However, it has repeatedly been reported that a number of novel gasifier designs have been developed. Those designs use high-temperature heat streams to internally crack tars in the producer gas and result in very clean gas streams [22,23]. Especially for the intended usage of this plant, such a clean producer gas system is evidently necessary in order to provide clean fuel for the microturbine and prevents corrosion in the heat exchangers employed within the plant.

3.2. Anaerobic digester

The anaerobic digester (AD) unit is modelled as a combination of heat exchangers, digester reactor and slurry separator, as shown in Figure 4.

Anaerobic digestion is a very complex process, employing a large number of microbial conversion steps that happen consecutively and/or simultaneously. Existing anaerobic digestion models in the published literature are therefore based on solving a large number of reactions for the production of biogas, a mixture of methane and carbon dioxide with traces of water vapour and hydrogen sulphide [24]. This very detailed reaction modelling may be a suitable approach when the main intention of the simulation is to model AD reactions in great detail, it however results in a rather complex model of the plant.

Instead of modelling all occurring reactions, the AD model developed in this study assumes that, based on performance data available in literature, a certain amount of biomass intake is converted into biogas.

Manure in this model is simulated as a mixture of water and non-conventional solids. A conservative solids content of 10% has been chosen, which is in accordance with literature [25]. Products of the AD processes are methane and carbon dioxide, which form the biogas stream, together with water and solids, which cover both unconverted solids and microbial cells grown during the process. The biogas stream is set up as containing 5% water vapor, with the remaining volume split into 60% methane and 40% carbon dioxide, again assuming common data from operational sources [16,26,27].

The structure of the AD model follows three main steps: first, heat exchangers (*AD-HE* and *AD-HLOSS*) are employed to provide the temperature level necessary to convert manure into

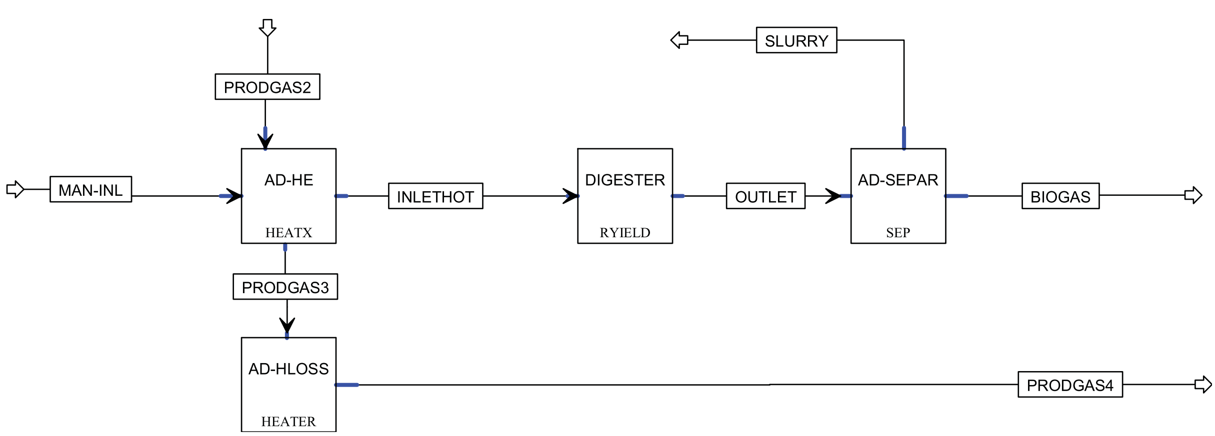

Figure 4. Anaerobic digester model flowsheet.

biogas. *AD-HE* warms the manure inlet stream *MAN-INL* to a temperature of 35°C while *AD-HLOSS* provides the heat that is lost for retaining the manure at that temperature, as detailed below. The producer gas stream is used as a source for the thermal energy in order to maximize the internal heat usage, as the *PRODGAS2* stream provides sufficient energy to maintain a mesophilic temperature range in the anaerobic digestion reactor and covers heat losses as described below.

The reactor block itself is modelled using an *RYIELD* block (*DIGESTER*), where a certain part of the solids is converted into methane and carbon dioxide. The amount of solid conversion and methane production rate has been chosen in accordance with literature, where values of 100–200 m^3 methane per ton of solids are stated [25,27–29].

Finally, a separator block *AD-SEPAR* is used to separate the liquid effluent, which contains water and unconverted biomass solids (stream *SLURRY*) from the *BIOGAS* stream.

The digester has been set up for a manure intake of 11 ton/day, which results in a tank size of around 200 m^3 for an average retention time of 20 days and could cope with a livestock size of around 100 cows [30].

Out of the total tank volume, 1/20 is replaced each day by new manure of ambient temperature, and the remaining volume needs to be maintained at the mesophilic temperature range. Therefore, the *AD-HLOSS* reactor includes calculations to simulate heat losses from the tank to the surrounding environment. The total heat taken from the *PRODGAS2* stream therefore consists of the heat losses of the tank (in *AD-HLOSS*) and the heat to warm up new manure from an ambient temperature of 20°C to the mesophilic range of 35°C (in *AD-HE*). It can be described as

$$Q_{\text{AD}} = Q_{\text{loss}} + Q_{\text{warm}} \tag{6}$$

with the heat losses being calculated with the formula following from Newton's law of cooling

$$Q_{\text{loss}} = UA(T_{\text{d}} - T_{\text{amb}}) \tag{7}$$

and the heat to warm the new manure being

$$Q_{\text{warm}} = \text{mc}(T_{\text{d}} - T_{\text{amb}}) \tag{8}$$

The digester surface area has been calculated based on a typical cylindrical digester shape with a volume of 200 m^3, and the overall heat transfer coefficient has been conservatively chosen based on own calculations and available literature [31].

In order to maintain a compact simulation, the authors believe that simplifying the occurring reactions during AD is an acceptable procedure, as results obtained are consistent with published operational results. The main intention of the model is investigating into the thermal optimization of applying a digester to the plant, not modelling microbial reactions in the highest possible level of detail. Biogas production values have been chosen conservatively and the digester model soundly represents the energy demands of a real digester, therefore from a thermodynamic point of view, the reactor design provides all information necessary in order to evaluate whether the reactor can be operated in the intended way.

It should be noted that, compared with the initial plant proposal as mentioned in [7,8], the authors have decided to change the digester type from thermophilic to mesophilic, which means that the digester operation temperature has been lowered from around 55°C to around 35°C. This was caused by two main reasons: First, nearly all data available concerning AD reactors and their energy needs as well as production volumes apply to mesophilic reactors. This however means that assumptions would have been necessary to scale mesophilic biogas production values to thermophilic levels, which results in uncertainty and errors. Additionally, most current digesters are operated in mesophilic levels due to the higher stability of the system when compared with thermophilic systems. So from a point of view of setting up a realistic simulation, the AD system was modified to a mesophilic level.

Once reliable operational data for thermophilic systems can be obtained, the mesophilic model can however easily be replaced by a thermophilic one, as the only changes would be a higher biogas yield and a higher heat demand resulting from the higher temperature level of the thermophilic digester. The increased biogas production rate however results in a lower reactor volume and hence less feedstock to produce the same amount of biogas, and from a heat perspective there is still enough internal heat available to provide the higher operation temperature range of thermophilic operation.

3.3. Microturbine

The microturbine model follows the basic structure of a real microturbine consisting of air compressor, air preheater, combustion chamber and expansion turbine. Its flowsheet is shown in Figure 5.

An ambient air stream *AIR-IN* is used for combusting the fuel and in the first step it is compressed in the *AIRCOMP* block from ambient pressure and temperature to a pressure of 3.35 bar. The air mass flow has been chosen to facilitate a minimum lambda of six, which means that the actual air flow is at least six times the stoichiometrical flow, as expressed by

$$\lambda = \frac{AFR_{act}}{AFR_{stoich}} \geqslant 6 \qquad (9)$$

where the stoichiometrically necessary amount is calculated based on the following main combustion reactions that occur in the turbine combustion chamber:

$$CO + \tfrac{1}{2}O_2 \rightarrow CO_2 \qquad (10)$$

$$H_2 + \tfrac{1}{2}O_2 \rightarrow H_2O \qquad (11)$$

$$CH_4 + 2O_2 \rightarrow CO_2 + H_2O \qquad (12)$$

The combustion chamber outlet stream temperature and pressure are limited by material constraints of the microturbine. The turbine blades can only be exposed to a certain maximum temperature and pressure, therefore a design specification restricts the combustion chamber to meet these values by means of regulating the amount of air intake; the parameters as well as other compressor performance data have been set consistent with literature values [32].

A work stream *W-IN* is connected to the compressor to simulate the shaft work input needed for the compressor in order to be able to calculate the net turbine work available, which is

$$W_{net,turb} = W_{shaft} - W_{in} \qquad (13)$$

The compressed air stream is then directed into a heat exchanger, where it is heated by the hot producer gas stream. The amount of heat exchanged between the hot and cold gas streams has been calculated by the equation

$$Q_{exch} = UA_{surface}\Delta T_{LM} \qquad (14)$$

with the logarithmic mean temperature difference being

$$\Delta T_{LM} = \frac{\Delta t_0 - \Delta t_L}{\ln \dfrac{\Delta t_0}{\Delta t_L}} \qquad (15)$$

and the design values for the geometry of the exchanger and overall heat transfer coefficients being chosen according to literature [33–35].

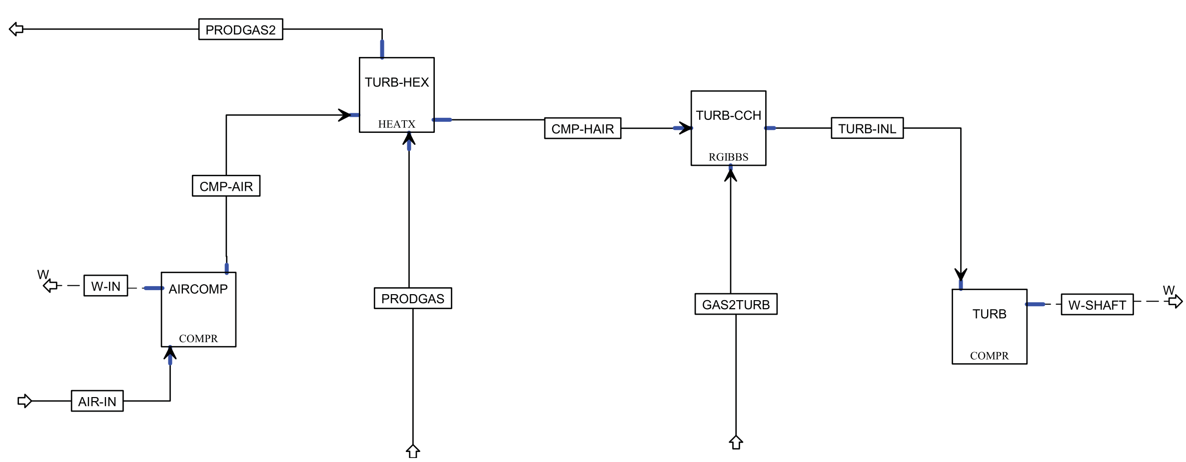

Figure 5. Microturbine model flowsheet.

After being preheated, the hot air stream *CMP-HAIR* enters the combustion chamber where the combustion reactions take place. The *TURB-CCH* block has been modelled as an *RGIBBS* reactor using the approach described above; alternative simulations with an *RYIELD* reactor using combustion reactions have shown very similar results, therefore both reactor types can be used for the simulation. On the account that Gibb's free energy approach also considers minor exhaust gases such as NO_X and SO_2, it has been chosen in the end.

The fuel gas stream *GAS2TURB* originates from the gas storage and consists of compressed producer gas and biogas. A pressure level of 5 bar is applied to satisfy minimum energy input requirements. This fuel gas is burnt and the hot and high-pressure exhaust stream *TURB-INL* is entering the turbine block *TURB* where it is expanded to atmospheric discharge pressure. The turbine inlet temperature and pressure as well as turbine performance parameters have been chosen in accordance to microturbine specifications as mentioned in [32,36,37].

A resulting work stream *W-SHAFT* carries the expansion work of the exhaust gases on the turbine blades, and an atmospheric exhaust gas stream *EXHAUST* leaves the microturbine section and is used in the wood dryer unit, as it still contains considerable amounts of thermal energy.

3.4. Gas storage system

The gas storage system acts as the fuel and thus capacity storage within the plant and replaces electric storage such as batteries that are normally employed in grid-independent plant designs. It consists of both a mixer for the producer gas and biogas streams, and a compressor that is used to simulate the compressed gas storage. An exit stream *GAS2STOR* is modelled that can be used to reroute part of the gas mixture to a storage, whereas the remaining *GAS2TURB* stream is burnt in the turbine combustion chamber.

The producer gas stream arriving at the gas storage system comprises of a relatively cold gas stream, as it has been used in the turbine and AD heat exchangers earlier on. In the block *STOREMIX*, it is mixed with the biogas stream that exits from the digester system, and the combined stream is then compressed in *STORECMP* to a pressure level of 5 bar. This level satisfies the microturbine minimum energy inflow and also minimizes the storage volume of the compressed gas. The compressor performance parameters are modelled based on the literature cited before [32], and similarly, the compressor power input is modelled by means of a work stream *W-IN2*. This means that the overall system network output can be calculated as

$$W_{\text{net,tot}} = W_{\text{net,turb}} - W_{\text{in\_2}} \tag{16}$$

This power output can then be compared with the actual power demand of the area that the plant is set up for, in order to configure the turbine power level and by that the share of fuel gas to be directed to the storage. The storage fuel ratio, which is expressed by

$$\sigma = \frac{m_{\text{GAS2STOR}}}{m_{\text{GAS2TURB}}} \tag{17}$$

can then be varied, which results in the combustion air flow through the turbine being changed accordingly, as it is connected via the lambda value. This variable air and fuel intake is known as a variable-speed/constant-temperature mode for regulating the microturbine power output and has been mentioned to be the most efficient way of operating a microturbine under variable load [38].

Initially, however, the storage fuel ratio has been set to zero and thus all fuel gas is directed to the turbine. Part of the simulation studies to be undertaken will address sizing issues of the fuel gas storage, as for an increase of the turbine output power, more fuel gas is needed by the turbine, and accordingly the fuel storage would be discharged. Simultaneously, for lower output power levels, the microturbine demands less fuel gas and as the conversion processes are continuous, the storage will be charged with the excess fuel. As mentioned before, microturbines can adopt different power levels and need around 20–30 s to adjust [13]. Accordingly, an adjusted fuel gas stream needs to be provided by the storage within this period.

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3.5. Wood dryer and electric heater

The wood drying facilities are the last remaining plant subsystem and are used to intensify internal heat usage. By using as much thermal energy as possible to dry the feedstock, the amount and quality of the producer gas and thus the efficiency of the whole generation system will be enhanced. A higher-cv producer gas results and storing this gas as a capacity for future generation seems more beneficial than trying to use the process heat in residential district heating schemes.

Both the wood dryer and the electric heater are simulated by means of two consecutive blocks. The wet biomass stream *BIOMSSIN* first enters the wood dryer, consisting of the blocks *DRY-REAC* and *DRY-SEP*, which uses the heat of the microturbine exhaust stream *EXHAUST2*. This stream contains minor amounts of NO_x, SO_2 and other combustion residues, so in order to prevent feedstock contamination, a conductive or indirect dryer design needs to be adopted, which means that the feedstock will not be in direct contact with the exhaust gas stream. Instead, a heated surface between the biomass and the exhaust gases will act as the evaporation heat carrier. Conductive dryers have a higher thermal efficiency than their convective or direct heat counterparts and are more suitable for products with higher moisture contents, such as wet biomass [39].

Initially, a moisture content of 60% has been implemented for the biomass intake stream *BIOMSSIN*. Fresh wood biomass normally contains between 30 and 60% moisture [40,41], however, in order to obtain information about the amount of exhaust heat that can be recycled into the process, this relatively high value has been chosen. Again, biomass itself is modelled as a non-conventional material stream based on its proximate and ultimate analysis, as described above.

The first reactor block, *DRY-REAC*, calculates the amount of water evaporated and the heat balance between the biomass intake stream and the exhaust gas stream for a preset exit moisture content. The moisture content of the biomass is hereby decreased to 10%, which has been mentioned as a target value for stable operation of the gasifier [41].

Both streams are then directed into the separator block *DRY-SEP* where the dried biomass stream is diverted from the vapour stream. The latter consists of the evaporated water from the biomass and the exhaust stream gases. The dried biomass stream *BIOMSS-W* is connected to the electric heater, whereas the exhaust stream *EXHAUST3* is modelled as being stacked. However, it could be used for additional heat transfer applications within the plant, as it still contains considerable amounts of thermal energy.

This heater model has been set up in accordance with the literature and the heat transfer values applied shows coherence to industrial dryer applications [21,39].

The electric heater forms the second feedstock drying unit and is the main power sink implemented in the plant model. Owing to that the plant is designed to be the single generation unit for an island consisting of residential power demand, no grid connection to other generators is intended. This however means that a balance between power demand and power generation needs to be ensured at each unit of time.

No electricity storage is intended in this design due to the negative impacts of batteries on the environment as well as on maintenance efforts and plant economics. This means that the microturbine as the only power generator needs to always generate at least the amount of power requested by the customers. However, no real-time mirroring of the power demand is possible for the microturbine operation, due to the time lack of several seconds when changing microturbine power output, as discussed in [7,13]. Instead, the microturbine generation will always exceed the demand, so a certain amount of power needs to be 'used up' to achieve generation/demand balance.

The electric heater forms the power sink to 'use up' this excessive power. It comprises of the two reactor blocks *ELECREAC* and *ELEC-SEP*. In the first block, water is evaporated from the predried biomass stream, *BIOMSS-W*, based on an energy calculation. The difference between power generation and demand, which is

$$W_{\text{avail}} = W_{\text{net,tot}} - W_{\text{demand}} \qquad (18)\leftarrow$$

is the amount of work that can be used for water evaporation. Based on the literature values from

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[39], a certain amount of energy is necessary to evaporate water from biomass, and the amount of water evaporated is calculated based on heater work input. For the plant feasibility study, the available work stream is initially set to 5 kW. The block then adjusts the biomass moisture content accordingly, and finally the block *ELEC-SEP* separates the exhaust water vapour stream *ELVAPOR* from the dried biomass stream *BIOMSS-D*, which is then directed to the gasifier.

Compared with the initial plant design, some changes have been implemented: due to the fact that the high-temperature exhaust stream from the turbine is not exhaustively used by the gasification heat exchanger, sufficient heat is still available for usage within the process, so the wood dryer uses this stream instead of the producer gas stream. Owing to the amount of heat available in the exhaust gas stream, a dried biomass moisture content of 10% or less can always be maintained, as follows from:

$$mc_{\mathrm{BIOMSS}-D}\begin{cases} = 10\% & \text{for } W_{\mathrm{avail}} = 0 \\ < 10\% & \text{for } W_{\mathrm{avail}} > 0 \end{cases} \quad (19)\leftarrow$$

4. SIMULATION RESULTS AND DISCUSSION

The plant design was simulated successfully, and the feasibility and reliability of the employed model was tested. Although detailed operational studies such as mirroring demand and issues such as storage sizing will form a part of further work, a number of variations were simulated to investigate the model robustness.

4.1. Scaling and feasibility results

First, a heat energy optimization analysis was undertaken to develop suitable scales of the individual units within the plant. As mentioned before, based on the individual heat inputs and outputs, the system heat streams were optimized by scaling each unit. The ratio between wood and manure intake found to provide best results is shown in Table I. It can be seen that a ratio of 1:10 was chosen for all cases but the smallest, whose slightly different ratio was caused by above-average digester heat losses. The minimum size of the plant was defined as the base case named *B1*. The raw feedstock inputs were then varied in order to check which scaling of the plant design provides suitable results, and the minimum plant size *B1* was scaled to around twice the wood intake and around three times the manure intake, a range within which all sizes provided feasible results.

Table I. Feedstock intake scaling.

Case name	Wood (kgh^{-1})	Manure ($\mathrm{ton\,day}^{-1}$)
B1 (base)	112.5	11
B2	150	15
B3	200	20
B4	250	25
B5	300	30

Table II. Scaling power output results.

Case name	$W_{\mathrm{net,tot}}$ (kW)←	$W_{\mathrm{net,turb}}$ (kW)←	$\eta_{\mathrm{turb}\rightarrow\mathrm{tot}}$ (%)
B1 (base)	60.418	72.551	83.3
B2	80.541	97.320	82.8
B3	106.732	130.085	82.0
B4	132.449	162.952	81.3
B5	157.924	195.947	80.6

The net overall available power and the net turbine output power resulting from these cases are given in Table II, additionally the amount of turbine power necessary to compress the gas mixture in the storage compressor is given by the plant efficiency.

It can be seen that for the range of common microturbine output power, which is up to around 200 kW, an available power level of 60–160 kW can be provided. This level perfectly fits smaller villages with 100–200 inhabitants. The efficiencies shown indicate that more than four fifth of the turbine output can be used as electricity for the customer. This however requests that the plant is designed for proper internal heat management, which results in low internal power needs. Values of up to 20% of output power being needed for the fuel compressor have been mentioned elsewhere [42] so the values mentioned above provide a realistic value, and given that waste is used as fuel feedstock, the overall efficiency is highly acceptable.

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In terms of plant size, the chosen base cases result in a digester tank size of between 200 and 600 m^3, and given that all other equipment is rather compact, the plant could be erected close to areas of demand.

4.2. Gasification unit results

The gasifier is fed with the above amount of biomass from the dryers and preheated air is used as a gasification medium. The air stream enters the gasifier heat exchanger and is heated to around 650°C, which provides sufficient heat to produce a high-quality producer gas. As the turbine exhaust gas stream is used as the heat source for the gasifier heat exchanger, this energy can be supplied continuously.

The hot gasification air and the pre-dried biomass particles then enter the gasifier and are converted into producer gas. The producer gas composition for the base case is shown in Table III and varies less than 2% for the different cases. The other minor components included are CH_4, C_2H_6, NO, N_2O, SO_2, H_2S and NH_3. Owing to the amount of moisture in the biomass, the producer gas contains a varying amount of water of around 3–4% when it leaves the reactor with around 710–730°C.

These results are comparable with the results of similarly scaled and designed gasifiers published in the literature [18,22,23,41]. Nitrogen and CO_2 values tend to be higher and CO values lower than those mentioned below; this however strongly depends on the gasifier air/fuel ratio that differs between different sources. Additionally, the gasification air temperature of 650°C is higher than in most applications, which also favours higher quality producer gas.

This producer gas composition results in a lower heating value of around 6.3 MJ/Nm^3, which is on the upper level of reported values. However, this again can be related to a different air/fuel ratio, a higher gasification air temperature and the fact that the wood moisture content is set to max 10%. In general, temperature levels applied tend to be lower than in this design, however this mainly results from the need to provide fuel for preheating the air. In this design, a high calorific producer gas can be created without the need for additional fuel, by using exhaust heat.

Table III. Producer gas composition (dry base, vol%).

N_2	CO	CO_2	H_2	Other
38.0%	32.7%	5.7%	23.6%	0.01%

The gas stream is then used in the heat exchanger to preheat the compressed air, where a temperature drop of around 350°C occurs. This shows that the producer gas stream contains sufficient energy to use it for preheating the compressed air. Afterwards, it is used as the hot stream medium for the AD heat exchangers, which results in a lowering of its temperature down to less than 100°C. This result is also realistic, as the manure stream is heated from ambient to around 35°C and the two mediums are in contact with each other. Besides of enhancing the overall process efficiency by lowering the temperature of the producer gas stream as much as possible, the gas storage compressor needs significantly less power to compress a low-temperature gas stream, so this temperature level is reasonable.

4.3. Anaerobic digestion unit results

The AD is set up with a slurry intake with an ambient temperature of 20°C. The heat duty calculation for this system reveals that for the cases chosen, the heat losses for keeping the manure at mesophilic temperatures are between 70–100% of the heat duty to warm up the new intake, as shown in Table IV.

The biogas stream composition for each of the cases is described in Table V, and a biogas lower heating value of around 18.8 MJ/Nm^3 can be calculated.

Table IV. Anaerobic digester heat calculation.

Case name	Q_{warm} (kW)	Q_{loss} (kW)	Percentage
B1 (base)	7.456	7.472	100.2
B2	10.160	9.190	90.5
B3	13.550	11.130	82.1
B4	16.950	12.910	76.2
B5	20.340	14.580	71.7

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Table V. Biogas composition.

Case name	CH_4 (kgh^{-1})	CO_2 (kgh^{-1})	H_2O (kgh^{-1})
B1 (base)	4.44	8.17	0.66
B2	6.05	11.14	0.90
B3	8.07	14.85	1.21
B4	10.08	18.56	1.51
B5	12.10	22.28	1.81

Table VI. Power output for storage ratio variations.

σ	$W_{net,tot}$ (kW)←	$W_{net,turb}$ (kW)←	$\eta_{turb\rightarrow tot}$ (%)
0 (base)	60.418	72.551	83.3
0.11	53.428	65.677	81.3
0.25	46.407	58.794	78.9
0.43	39.367	51.919	75.8
0.67	32.243	44.999	71.7
1	25.040	38.055	65.8

On account of both streams being mixed afterwards, this significantly increases the heating value of the gas mixture and thereby minimizes the gas compressor power input, which is necessary to maintain a minimum energy intake flow for the microturbine.

4.4. Gas storage and compressor system results

The compressor power necessary for the different cases has been mentioned in Table II. As it is strongly related to the temperature of the producer gas stream, an efficient internal heat usage not only results in better process efficiency, but also in the ease of omitting a gas cooling system prior to the compressor.

To investigate the plant flexibility, the storage ratio has been varied for the base case scenario. As the microturbine efficiency strongly decreases for power outputs less than 50% of the nominal turbine power [38], it was decided that the turbine should always operate on at least half its nominal power in order to provide operation stability and maintain efficiency. Therefore, storage factors in the range of

$$0 \leqslant \sigma \leqslant 1 \qquad (20)←$$

have been investigated for the base case, which means that between none and half of the producer gas/biogas mixture is not burnt in the turbine, but sent to storage. The impacts of this variation on the turbine output power and the total available power are shown in Table VI.

As expected, with a rising sigma, the total turbine output power as well as the available power decrease linearly from 70 kW to around 40 kW. As the power for the fuel compressor stays nearly constant, the total efficiency decreases.

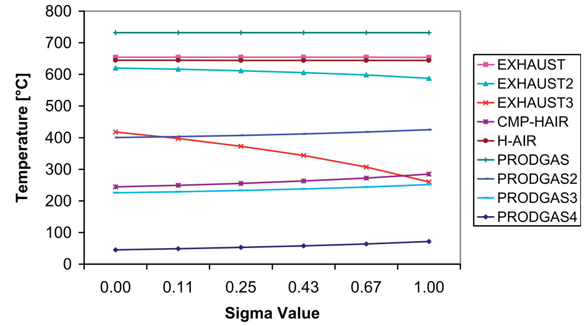

Figure 6. Plant stream temperature profiles.

The influence of varying the storage ratio on some other key stream temperatures of the plant is shown in Figure 6.

It can be seen that although the nominal power output of the turbine decreases, the *EXHAUST* stream temperature stays constant. This is obviously related to the temperature of the compressed turbine air *CMP-HAIR*, which rises from 240°C for $\sigma = 0$ to 280°C for $\sigma = 1$. As less fuel gas is burnt in the turbine combustion chamber, less air mass flow is necessary. This air flow is however preheated by the producer gas stream (*PRODGAS*), and as nearly the same amount of heat is transferred in the turbine heat exchanger, this results in a higher temperature of the compressed air stream.

Although the exhaust gas mass stream decreases due to less fuel being burnt, it still contains enough energy to preheat the gasification air. As the *H-AIR* stream temperature is being pegged to the *EXHAUST* temperature level, this means that the lower exhaust gas mass flow needs to provide the same amount of heat for the gasification air, which results in the *EXHAUST2* stream temperature decreasing from around 620°C for $\sigma = 0$ to around 580°C for $\sigma = 1$.

It is also shown that the *EXHAUST2* stream still contains enough energy to maintain the maximum moisture content in the wood dryer of 10%. As the same amount of heat is necessary due to a constant wood intake, the *EXHAUST3* stream temperature decreases from 420 to 260°C over the variation of σ due to its decreasing mass flow. However, the dryer can continuously produce biomass with a moisture content of 10% over the whole range.

The *PRODGAS* temperature is close to constant over the whole range, which results from the gasification air stream *H-AIR* temperature being pegged to the constant *EXHAUST* stream temperature. The fact that the *PRODGAS2*, *PRODGAS3* and *PRODGAS4* temperatures slightly raise is again related to the turbine heat exchanger, and the decrease in the compressed air stream mass flow.

However, after passing the two AD heat exchangers, the producer gas stream *PRODGAS4* reaches a temperature level close to the digester temperature, therefore a storage ratio of 1 should not be exceeded as it increases the amount of power for the fuel compressor. This fits with the turbine not being operated on less than 50% of the nominal power.

4.5. Wood dryer and electric heater results

The electric heater acts as the power sink for the amount of power generated that is not needed by demand. In the base case it is set to a flat power intake of 5 kW. As the wood dryer always provides enough exhaust heat to be able to dry the wood chips from a moisture content of 60–10% as described above, the electric heater power intake is limited to the amount of energy necessary to evaporate the remaining water.

The *BIOMSS-W* stream consists of a 50 kgh^{-1} flow of biomass with a moisture content of 10%, so a maximum of 5 kgh^{-1} of water is available for evaporation. However, the feedstock cannot be dried to 0%, so a maximum of 90% of this water has been assumed to be available for evaporation.

For the base case and the amount of energy necessary to evaporate water from wood, a continuous power intake of $W_{\text{avail}} = 6.25\,\text{kW}$ results for maximum water evaporation. This translates into a fraction of around 10% of the total available power output when the turbine is running on full load, or 25% when the turbine is running on half load, which has been defined as the minimum power output.

These values seem not satisfactory to be able to always enable supply/demand balance, especially when large fluctuations occur in the demand profile, which is a likely situation for small groups of domestic users.

However, to assume a flat power intake of 6.25 kW over long-time intervals of, for example, 1 h is unrealistic, as the microturbine output power will be adjusted in order to meet the lower load.

The amount of continuous power input for drying in the heater can be calculated as the sum of time-weighted incremental power inputs by

$$W_{\text{avail}} = \frac{\sum P_i \Delta t_i}{3600\text{s}} \quad \text{in W} = \text{J s}^{-1} \qquad (21)$$

where P_i stands for the incremental amount of power input (in W) that is necessary for a period of time defined by Δt_i (in s).

As all fuel mass flows are based on kgh^{-1}, the continuous power input W_{avail} is averaged for a total time frame of 1 h, while the incremental period of time is set to 30 s, as microturbines need around 20 s to adopt a new power output level [13,43]. The difference between the two microturbine output power levels will need to be consumed by the electric heater in the time frame of adopting a new output power.

This however means that higher short-term power intakes P_i can be accommodated by the electric heater, as long as within the longer total period of 1 h the total power intake is less than 6.25 kW.

A representative load profile of fitting size from [44] was used to develop a range of relative incremental power changes in order to gain information on the level of common demand fluctuations and on whether this design could accommodate them. The data provide 5-min domestic load profiles, and relative demand

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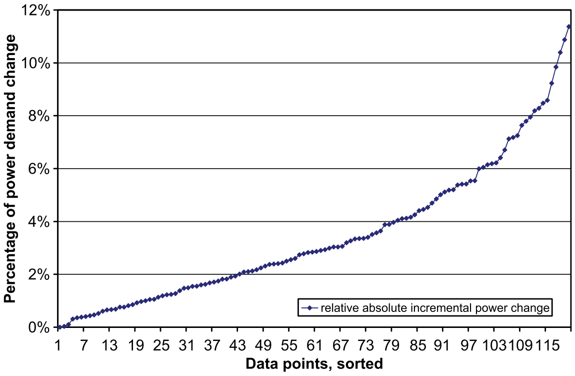

Figure 7. Relative absolute incremental change in demand.

changes of up to $\pm 12\%$ were found between two data steps, i.e. within five minutes. However, demand fluctuations on average are significantly lower. Figure 7 shows the sorted and relative absolute load changes for a random one-day period, and it can be seen that the majority of demand changes lie well below 8%.

Based on these values and a full power output as mentioned above, a value of $W_{\text{avail}} = 2.4\,\text{kW}$ has been calculated, which is well below the maximum value of 6.25 kW to care for safety margins. Therefore, it can be stated that the electric heater can accommodate load fluctuations by 'using up' excessive electricity when matching demand and supply in a non-grid environment. However, further simulation studies will need to address these issues in more detail, as all fluctuations will have to be accommodated by the plant in order to provide reliable and continuous power.

5. CONCLUSIONS AND FURTHER WORK

The recently proposed novel micro-scale combined feedstock biomass generation plant, which combines gasification, anaerobic digestion and microturbine technology, is feasible and can provide electricity on a scale down to 50 kWe. Combining wet and dry feedstock utilization results in a better internal heat management, as high-temperature thermochemical processes can support heat-demanding biological processes. Each plant unit was scaled to a size that optimizes its internal heat usage and that ensures a high overall plant efficiency. A detailed simulation model of the plant has been developed and was tested exhaustively.

The modelling of the plant was undertaken in Aspen Plus chemical engineering software, a standard and proven software for such simulations. The feasibility checks and simulations have proven to provide reasonable and realistic results compared with the literature values from operational plants. The power range investigated provides a fitting size for remote areas and due to high internal heat usage, a high plant efficiency can be achieved.

Therefore, the plant design has proven to be a realistic solution that provides major benefits from locally available energy sources for areas where no grid connection is or can be provided. The authors have chosen a conservative approach on modelling the plant, and all parameters and performance characteristics were intensively checked against running applications. Therefore, the developed plant model suitably represents the plant technology and can be used for further studies with regards to operation optimization and dynamic simulations of the plant.

Furthermore, it has been shown by means of a first fluctuation analysis that the plant design can cope with changing demand by employing a power sink. More detailed studies of the transient behaviour and related issues will need to be undertaken, however this way of matching supply and demand is a promising novel approach in rural electrification and overcomes the obstacle of using renewable energy to meet customer demand in time. Further work will address issues such as matching demand by analysing and using domestic load patterns, as well as storage sizing and plant economics. The model, however, provides a new focus on plant design and overcomes barriers from both power engineering and thermodynamic and mechanic plant optimization, when compared with the prevailing base load designs of biomass plants and the high intermittency of other renewable energy sources. Owing to the results of the feasibility studies undertaken in this paper, a prototype plant will also be set up in order to gain better understanding of the plant characteristics.

NOMENCLATURE

A, $A_{surface}$	= exposed area, heat exchanger surface area (m^2)
AFR	= air flow rate (kgh^{-1})
c	= specific heat capacity ($kJkg^{-1}K^{-1}$)
cv	= calorific value (MJ/Nm^3)
G, ΔG	= Gibb's free energy, change in Gibb's free energy (J)
ΔG_f	= Gibb's free energy of formation ($Jmol^{-1}$)
H	= Enthalpy (J)
m	= mass (kg)
mc	= moisture content (vol—%)
n	= amount of a substance (mol)
P	= Power (W)
Q	= Heat amount (J), Heat transfer (W)
S	= Entropy (JK^{-1})
σ	= Sigma value (–)
T, T_d, T_{amb}	= Temperature, digester, ambient temperature (K)
ΔT_{LM}	= logarithmic mean temperature difference
Δt_0, Δt_L, Δt_i	= temperature difference at stage 0, L, i (K)
U	= overall heat transfer coefficient ($Wm^{-2}K^{-1}$)
W	= Work (J)

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How Small can Micro-Scale Generation be? Size analysis of a novel biomass power plant

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Abstract—**In times of an ageing power grid in many developed countries and large shares of non-grid-connected areas in developing countries, alternatives to the conventional power infrastructure of centralized generation and grid distributed power become ever more important. Using locally available energy carriers for micro-scale decentralized generation could provide both energy self-sufficiency and security of supply for remote customers. From a point of view of availability, only biomass can provide ongoing power, and being a renewable energy source micro-scale biomass generation has an enormous potential to shape a new power sector.**

As most remote regions are sparsely populated, such a power plant must be as small as possible, whilst still providing flexible operation, robust technology and little maintenance efforts. This paper will analyze a range of feasible scales for such a plant, and it will be shown that such generation systems can feasibly be downsized to small regional levels.

Index Terms—**biomass, micro-scale, waste-to-power, grid independent generation, anaerobic digestion, gasification.**

I. Introduction

In areas where a grid connection is either not available or prone to disruption, remote electrification by means of island generators provides the sole source of power, a service which has a major benefit on all facets of life. These island solutions normally provide power for a number of hours each day, and are based on fossil fuel diesel gensets. Renewable energies could provide a major impetus and improve this situation, however they are normally intermittent and thus not suitable for ongoing power supply unless expensive and maintenance-intensive electrical storage is employed.

As the only non-intermittent renewable energy source, biomass could be used for ongoing power provision. Feedstock availability in general is also high in remote regions. Hence, a small biomass based power plant that provides energy 24/7 would bring major benefits to large areas of the world.

The main challenges for such a plant are operational. The plant needs to be able to generate to meet the demand, making flexibility crucial. Power demand fluctuates significantly over the course of the day and depends on several factors such as time, season, temperature etc. Assuming that no grid connection would be available to compensate for demand changes, the plant would need to closely follow this volatile load pattern. Additionally, as this would be in remote locations, robustness of technology, operational stability and low maintenance become important factors. Finally, sufficient ongoing feedstock sourcing in the proximity of this plant is a must to avoid feedstock being transported and to achieve energy self-sufficiency.

A plant design that undertakes to overcome these manifold obstacles has been proposed by the authors [1]. This micro-scale plant uses well-known biomass conversion technologies (gasification and anaerobic digestion) to convert biomass into a fuel gas mixture. A microturbine generates power of a suitable amount to meet local demand. Matching of supply and demand is achieved by using fuel storage and flexible turbine operation rather than batteries.

An extensive simulation model of this plant was developed and feasibility as well as initial sizing studies undertaken. These have shown that the plant design is feasible and can provide continuous power [2]. Further operational studies have revealed that the system is able to accommodate high levels of load fluctuations [3].

Current biomass power plants are mainly designed and optimized towards a larger scale, 1MW upwards, and provide a flat power output [4-6]. As this results in both the need of network infrastructure and problems in sourcing sufficient feedstock locally, the question that needs to be faced is "how small can effective micro-scale generation be?"

In order to evaluate possible deployment strategies of this novel biomass power plant design, the paper covers a detailed size limitation study that reveals minimum and optimal plant scales. It will be shown by means of energy and technology analyses how small such a plant system could be designed, and it will be shown that the size range is of high interest for both rural electrification purposes and as a way of replacing uneconomic grid connections in remote locations.

II. Methodology

Based on the plant model described in a previous publication [2], energy analyses of each of the main sub-systems of the plant were undertaken. This means that the two conversion systems, gasification and anaerobic digestion (AD), and the generation unit, microturbine, were analyzed to reveal their size limitations. In a second step, each unit's energy supply and demand balance was calculated and included in a total system balance. This provides a range of feasible sizes of optimized sub-units which result in an optimized overall plant system.

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Finally, a feedstock sourcing analysis was undertaken to reveal what power output is achievable with a given amount of feedstock, and what limitations exist for the requirement of ongoing and sustainable feedstock provision.

A. Anaerobic Digester (AD) size analysis

The anaerobic digester (AD) unit mainly consists of a tank in which bacteria digest wet feedstock such as manure, sludge or vegetable waste, and produce a gas mixture of CH_4 and CO_2. The feedstock intake is kept at a reactor temperature of 35°C and is held for a period of 20d. In intervals, new feedstock replaces part of the tank volume, which means that this new feedstock needs to be heated to the reactor temperature.

The AD size limitation mainly depends on its energy balance, as the digester should provide more energy than it consumes in order to be a net energy providing conversion technology. Whilst AD technology itself has been known and employed for decades [7, 8], energy analysis of such a system is a more recent development, as in history the main intention of the digester was hygienic treatment of manure. Using it as an energy source has only recently gained interest and resulted in a more detailed discussion of its energy streams [7, 8].

The main energy output stream of an AD depends on the amount and consistency of the biogas produced, given that the heat of the biogas stream will not be usable. Its energy demands can be classified as [8, 9]

- the electricity or heat for heating the inflow manure to the digester temperature
- the electricity or heat for maintaining the digester temperature, i.e. for compensation of digester heat losses
- the electricity for mixing the tank and
- the electricity for pumping and for other auxiliary services.

For the digester system employed in this plant design, an energy analysis considering these main energy inputs was undertaken.

The heating energy (Q_{heat}) normally forms one of the two main energy demands of an AD system [8, 9]. It depends on the temperature difference between ambient feedstock inflow temperature and reactor temperature, and on the heat capacity of the manure. This energy demand can be calculated as a function of the wet feedstock intake m_1 [2].

The energy demand to compensate for the digester heat losses to its surroundings (Q_{loss}) forms the second main energy demand of an AD system [8, 9]. Although the tanks are normally insulated, a heat transfer between the digester walls and the surrounding atmosphere occurs, as the temperature within the reactor is normally above the ambient temperature. This energy demand thus also depends on the temperature difference between reactor and surroundings, as well as on the digester surface and on the overall heat transfer coefficient, a constant related to the insulation of the digester [2].

The digester surface area itself however is a function of the daily feedstock intake. Feedstock is kept in the tank for 20 days, and each day a certain amount is replaced with new intake. Thus, the daily intake volume determines the digester tank volume and hence its surface area. Therefore, for a given digester geometry the digester surface area A can be formulated as a function of the daily feedstock intake of the digester system, and hence the energy demand itself becomes a function of the manure intake m_1, which means that the energy demand of those two main input streams can be formulated as

$$Q_{main} = F(m_1) = Q_{heat} + Q_{loss} \quad (1)$$

These energy requirements can be provided by both heat or electricity, as heat is the energy carrier needed. The mixing and pumping energy demands however have to be provided in the form of electricity. It has been calculated that for common AD systems, these demands are small in comparison to the above two main energy streams, and hence they can be included in the calculation in form of percentages [8, 9]. For the AD size limitation studies of this paper, values have been used in accordance with literature, and the total energy demand for pumping, mixing and auxiliary services was chosen as 10% of the heating and heat loss energy, which means that the total system heat demand can be calculated as

$$Q_{AD} = 1.1 Q_{main} \quad (2)$$

B. Gasifier size analysis

Gasification is the substochiometric combustion of dry biomass such as wood, straw or crops. Biomass feedstock is heated and partly oxidized, and a gas mixture of mainly N_2, H_2, CO and CO_2 is produced. Solid residues of this process are char and ash, and some tars in the producer gas. Historically these tars have hindered the wide-scale employment of such systems, however new technologies such as high-temperature gasification have overcome this obstacle to a high extent and made small-scale gasifiers feasible [10, 11].

Gasification itself, although only partly oxidizing the feedstock, is an exothermic process, in that the energy of combustion is received from the feedstock [12]. Theoretically, this process can hence be minimized indefinitely, as it itself is not subject to size limitations.

A certain amount of heat is necessary to maintain ongoing feedstock conversion. The air that is used as a gasification agent needs to be provided in the temperature range of around 700-800°C in order to facilitate the drying, pyrolysis and oxidation zones within the gasifier [13, 14]. This can be achieved by either utilizing the process heat of the producer gas, or by supplying this energy by combusting part of the feedstock. Alternatively, this energy could be provided by other high temperature plant heat streams. In either case, the energy demand for preheating the gasification agent can be calculated as a function of the raw wood intake m_2. The ratio between feedstock intake and gasification agent should be kept constant, and an air/fuel ratio of 1.5 based on dry ash-free biomass has been chosen for the model in this study [2]. The gasifier heat exchanger geometry is fixed and thus the heat transfer coefficients are constant, so the heat exchanger energy demand (Q_{GasHEX}) only depends on the wood intake m_2.

Heat losses from the gasifier to its surroundings occur, however with <1% they are negligible, as throughput times are small and in the order of several minutes [12].

The gasifier however can only process feedstock with a certain water content. During the gasification process all water will be vaporized, high water amounts thus reduce the process efficiency and result in related issues such as fouling. Water contents should typically be lower than 20% [15]. Fresh wood can contain up to 60% moisture [15, 16], thus drying the feedstock prior to it being gasified is essential. This can be facilitated by a wood dryer that uses either electricity or thermal energy to vaporize the excess water. Convective or conductive dryers can be applied, the latter using a heated surface between the wood and the heating medium whilst the former applying direct contact between the two.

The energy demand of the dryer (Q_{Dryer}) will depend on the amount of water to be evaporated from the raw wood chips. In either case, the dryer geometry will remain constant once it has been chosen, so the energy demand of the dryer becomes a function of the initial moisture content of the feedstock. The heat demand to evaporate water from various biomass feedstocks can be assumed as a constant, depending on the size and type of feedstock [17]. The amount of water to be evaporated however depends on the wet feedstock intake m_2, thus the overall energy demand of the dryer becomes a function of the wood intake, which means that the total gasifier heat demand can be formulated as

$$Q_{Gasifier} = F(m_2) = Q_{GasHEX} + Q_{Dryer}\,. \tag{3}$$

C. Microturbine Size Analysis

The energy requirements of the microturbine are dictated by the work required to compress the combustion air prior to it entering the combustion chamber, and the energy to preheat the compressed air before it gets in contact with the fuel gas.

Whilst the work demand is automatically provided by part of the microturbine expansion shaft work as both the turbine and the compressor are mounted on the same shaft, the energy to preheat the combustion air can be provided by either the turbine effluent using a recuperator, or by another heat stream within the system [18].

Therefore, the microturbine does not have any inherent size limitations on the basis of its energy analysis. However, available microturbine technology is limited to sizes of 25kW upwards [18, 19], which results from a lower conversion efficiency with lower sizes, so this could be seen as a natural size limitation, although even smaller turbines down to 1-5kW were reported in literature [19].

III. Results and Discussion

Based on the energy analyses described in the above chapter, both conversion technologies were evaluated with regards to their scale limitations. Afterwards, a whole system analysis was undertaken to reveal suitable combinations of the single units. Finally, the feedstock necessary for a chosen combination of unit sizes was analysed.

A. Anaerobic Digester Size Analysis

The energy demand of the digester and its three main components are shown in Figure 1 as a function of the raw manure intake m_1. It can be seen that for small scales, the heat losses (Q_{loss}) are higher than the heat demand of the digester (Q_{heat}), whilst for larger scales the heat demand is the main component of the overall energy demand.

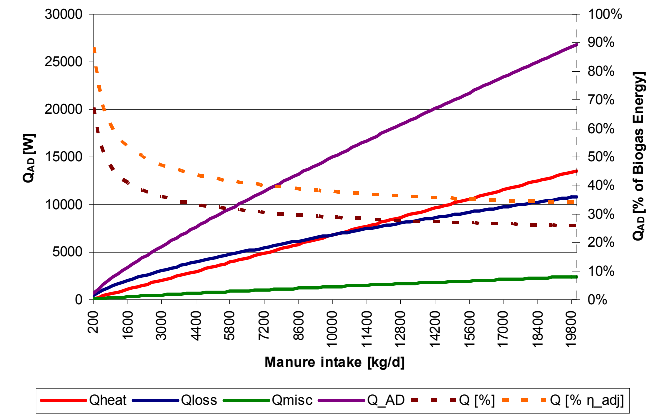

Fig. 1. Anaerobic Digester System Energy Demand and Energy Balance.

The total energy demand is also shown as a percentage of the energy contained in the produced biogas. It has to be considered that the energy demand of the digester cannot be provided without energy transfer losses. Hence, the adjusted energy demand of the digester as a percentage of the biogas energy was also calculated including conversion efficiencies, and those higher percentages are also shown in Figure 1. The energy demand of the digester includes electricity and heat, thus the efficiencies of converting the biogas chemical energy into heat (90%) and electricity (30%) were applied.

It can be seen that for small digester sizes (<1 ton/day of manure), the total energy demand can be close to the energy of the biogas, which results in a net zero or even negative energy balance for those small digester systems and implies that the system fails to be a feasible energy provider. This means that a chosen size for this AD system should be above 1 ton/day of feedstock. The chosen base-case size of 11 ton/day of slurry results in the total energy demand being between 30-40% of the digester output, which is acceptable.

B. Gasifier Size Analysis

The energy demand of the small-scale downdraft gasifier is shown in Figure 2 as a function of the wood intake m_2. Both the heat demand to preheat the gasification agent (Q_{GasHEX}) and the dryer heat demand (Q_{Dryer}) are shown. It can be seen that Q_{Dryer} is significantly larger than Q_{GasHEX}. The initial moisture content of 60% is lowered to 10%, hence there is a significant amount of water to be evaporated from the feedstock.

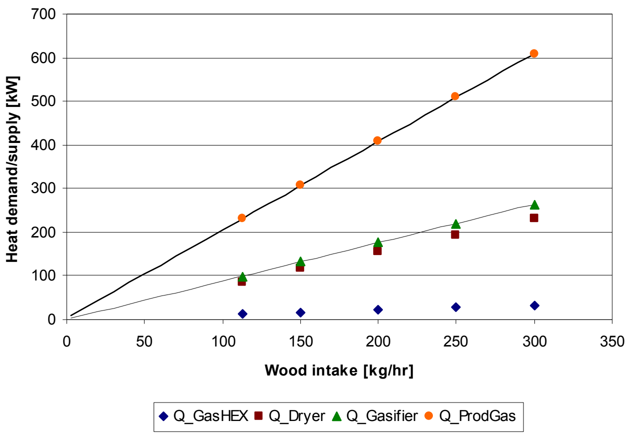

Fig. 2. Gasifier Energy Demand and Energy Balance.

The energy balance of the gasifier can be analysed by considering the thermal and chemical energy of the producer gas stream. As the gas stream leaves the gasifier at a temperature of around 700°C, the thermal energy stored in the gas is considerable. Together with the chemical energy of the fuel components hydrogen and carbon monoxide, the energy stored in the producer gas is shown as the line named $Q_{ProdGas}$.

For the energy demand and supply balance of the system, the trend lines are shown in Figure 2 and it can be seen that the energy demand is always below the amount of energy contained in the producer gas. The linear trend lines were verified by adjusting the simulation model to lower wood intake amounts, and the linear trend can be assumed. As expected, the exothermic gasification process thus does not have an energy size limitation and could (in theory) be minimized indefinitely, as long as the reactor technology can be designed for the respective size.

C. Combined System Size Analysis

After having analyzed the energy balances of the two single conversion systems and after having evaluated feasible ranges of scale, an additional analysis covered the combination of these units into the proposed plant design. One objective of the plant design was high internal heat usage within the system. Thus, it was decided to use the producer gas as the heat source of the digester, and the microturbine exhaust stream as the heat source of the wood dryer and gasification heat exchanger. This however has only a slight impact on the energy balance of the whole system when compared to the single unit energy balances.

In a two-variable approach, a range of sizes of the AD and the gasification system were combined to evaluate the overall energy balance and to understand which sizes are feasible. The analyzed range of size combinations is shown in Figure 3 as an area chart, and the traffic-light system was used to classify the energy balance result. For a given pair of biomass feedstock intake ($m_1|m_2$), Figure 3 shows whether the system energy balance is in equilibrium (green-checkered area), positive (orange-dotted area) or negative (red-dashed area).

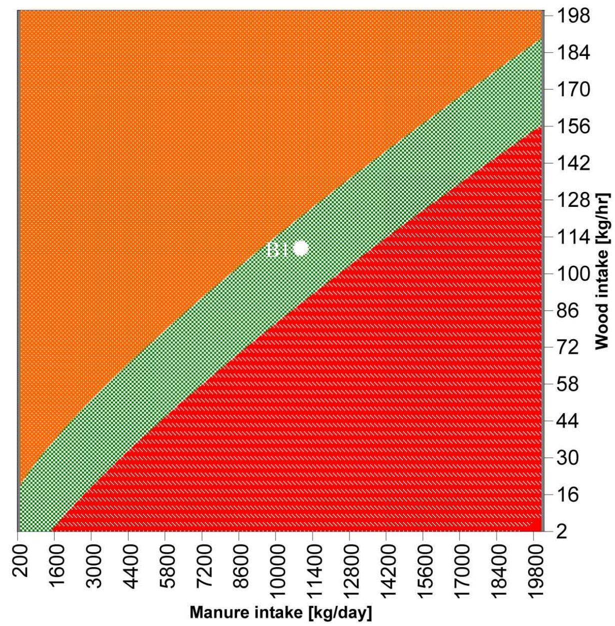

Fig. 3. System Energy Balance for Pairs of Manure and Wood intake.

An energy balance in equilibrium means that the energy demand and supply are equal, hence the system's energy demand can be provided by its own energy supply, which means that the system is feasible. For the energy balance becoming positive, it means that less energy is demanded than could be supplied, which also results in a feasible system; however it also means that some energy is wasted. Whilst for the energy balance becoming negative, the energy demand of the system can no longer be provided within the system, and external energy sources would need to be provided, which leads to infeasibility for a stand-alone system.

However, although all pairs ($m_1|m_2$) in the green and orange area of Figure 3 provide a feasible system, it should be considered that an optimized system will be restricted to the green area only. For example, the pair chosen as the base case of the plant design modeling analysis (*11 t/day of manure | 112.5 kg/hr of wood*) is shown in Figure 3 as the small white dot named 'B1' and lies in the green area, which means that this size combination results in an optimized system. Should a higher amount of wood and/or a lower amount of manure be used, then the point would move into the orange area; this still results in a feasible system; but significant amounts of energy would be wasted, as the energy demand is way below the energy supply. Such a system should only be employed if plenty of biomass is available and if energy optimization becomes a less important consideration over others, e.g., waste disposal.

Once a feasible pair of biomass intake ($m_1|m_2$) has been chosen, the turbine power level that results from the production rates of biogas and producer gas can be calculated [3]. This would however be the level that a turbine could be operated on continuously. The plant will be running flexibly to accommodate load fluctuations, and the microturbine will for efficiency reasons be operated between 50-100% of its nominal power level [2]. Based on the overall load factors for the continuous flexible operation of the plant for a given set of load profiles, a load range can be calculated that results in the desired average load level.

For this range of operational power levels, a final analysis needs to evaluate whether the microturbine exhaust heat stream can provide sufficient energy to the gasification system and the dryer. The results of a two-variable approach to analyse the energy balance of pairs of turbine output and wood input are shown in Figure 4 in a similar area chart where the traffic-light system is again employed to indicate the feasibility of the system.

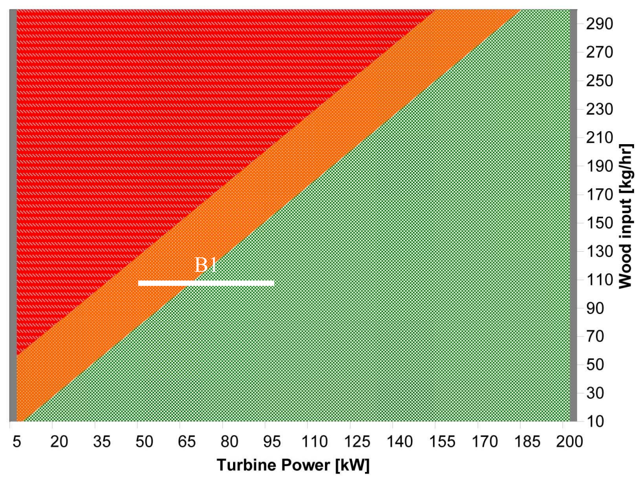

Fig. 4. System Energy Balance for pairs of Turbine Power and Wood Input.

For a given wood input, the turbine power range which can provide sufficient energy is shown in the green-checkered area (positive energy balance – feasible); the power levels that result in insufficient exhaust heat for the process are shown in the red-dashed area (negative energy balance – infeasible); and the orange-dotted area shows the power range for an energy balance in equilibrium.

For a given range, low turbine power levels may be within the orange area, as shown in Figure 4 for the base case B1 (power range 50-100kW$_e$); however this means that the operational range of the turbine is optimized energetically.

D. Feedstock Analysis

The final point for determining the appropriate system capacity can be two-fold: Should plenty of feedstock be available locally, then the overall peak total energy demand of the intended power customers will determine the size of the power plant, as the plant will need to provide this maximum peak total energy demand. Once this power level is known, the plant can be sized using any feasible combination of feedstock.

Alternatively, if only a certain amount of feedstock is available on site, a power output has to be calculated to evaluate whether sufficient power can be sourced from the available feedstock to meet local demand. This follows from the fact that local feedstock should be the sole fuel source for this plant. Should the local power demand exceed the locally available feedstock level, it however has to be evaluated whether transporting feedstock to the site or being unable to satisfy the peak power demand is the option to choose. The former will result in feedstock transportation costs and annihilates the intended energy self-sufficiency, whilst the latter may result in inconveniences for the customers.

In either way, the power level, once chosen, can basically be met by any combination of both wet and dry feedstock, as long as the aforementioned limitations are observed. That ratio of the two feedstock sources should naturally depend on the local availability of feedstock to be used for ongoing power supply.

For wet feedstock, manure amounts that can be utilized for AD conversion depend on the head units of a livestock herd and on housing and storage conditions. Average manure amounts can be estimated based on values such as in [20], and their respective potential for power generation can be estimated from [3]; this results in the number of head units necessary for 1kW$_e$ continuous power as shown in Table I.

TABLE I: MANURE AND GENERATION POTENTIAL FROM LIVESTOCK FARMING

	Cattle	Horse	Pig	Sheep	Poultry
manure [kg/d]	50	23	5	4	0.5
head units for 1kW$_e$	7	12	55	70	310

Notes: Manure includes feces, urine, bedding material and fodder residues for permanent livestock housing during the year, per head unit. Total Solids contents: 45% (poultry), 25% (all remaining). For mixed husbandry (grazing and housing days) average daily manure amounts need to be corrected.

For dry feedstock, forestry waste wood or short rotation coppice (SRC) could be used as a source of wood chips. For a given surface area, average annual dry matter yields such as in Table II can be expected [21, 22]. Using the conversion efficiency from wood to power generation of 1kg/hr of wood ≈ 1 kW$_e$ [1], Table II also shows the estimated generation capacity based on the available land surface area (in hectares).

TABLE II: WOOD AVERAGE ANNUAL YIELDS AND REQUIRED AREA

	SRC	Forest residues
yield [kg$_{dry}$/ha·a]	6,000-10,000	1,400-2,300
ha for 1kW$_e$	0.9-1.5	3.75-6.25

IV. CONCLUSIONS AND FURTHER WORK

The main conclusions of the sizing studies undertaken in this paper are the following:

The novel micro-scale biomass generation plant can be sized conveniently in order to use locally available feedstock for ongoing power provision.

When scaling down the AD system, with falling size heat losses and heating demand increase significantly and can reach levels of more than 50% of the energy content of the produced biogas for sizes of less than 1 t/d of feedstock. Without a supporting external heat source, such small digesters will cease being an efficient energy source and will become infeasible.

The gasification system itself is based on exothermic reactions and thus it can always source its energy needs from either its feedstock or the heat of the producer gas stream. It thus does not have size limitations within a realistic range.

A detailed system analysis of connecting the sub-units to the whole plant system revealed a broad range of feasible scales. Using the area charts shown above, it can easily be seen whether a combination of two amounts of feedstock will or will not result in a feasible plant size. It can also be calculated what amount of power such a combination would be able to generate continuously.

Based on the feedstock available on site and the estimates given in this study, it can thus be calculated whether sufficient power can be sourced, and whether the plant can thus provide energy self-sufficiency.

Feasible feedstock combinations should however be limited to values that allow high and efficient internal heat usage (green areas). Otherwise, a significant amount of heat will have to be stacked, which results in energy losses and thus feedstock wasting.

After an initial sizing analysis for which this paper provides a detailed guideline, it can be considered whether employing such a plant could be economically and ecologically interesting. In such a case, a more detailed study however needs to follow. This should then include detailed plant simulations as well as more detailed feedstock analyses based on local tests. With the findings of this paper, the efforts of such a detailed study can however be significantly limited: the detailed studies can remain for feasible size ranges and feedstock combinations that prove beneficial, instead of applying it for all possible combinations and plant sizes.

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Biographies

Mathias Loeser graduated from the private university of applied sciences Nordakademie in Elmshorn, Germany in 2007 with a Master equivalent German Diploma degree with distinction in Industrial Engineering and Business Management and the Nordmetall trust award as best in year. He is now pursuing a PhD at the University of Bath. His areas of interest are in biomass based generation technologies, renewable energies and plant design, modelling and operation as well as process engineering in general.

Miles A. Redfern (M' 1979) received his BSc degree from Nottingham University in 1970 and PhD degree from Cambridge University in 1976. In 1970, he joined British Railway Research, and in 1975, he moved to GEC Measurements where he held various posts including Head of Research and Long Term Development and Overseas Sales Manager. In 1986, he joined the University of Bath with interests in Power Systems Protection and Management. Dr Redfern is an active member of several international technical committees and has authored approximately 200 publications which have been presented worldwide.

NOVEL COMBINED FEEDSTOCK MICRO-SCALE BIOMASS GENERATION PLANT FOR REMOTE POWER SUPPLY - MODELLING AND SIMULATION RESULTS

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ABSTRACT: Providing power to remotely located areas by using conventional grid-connection can incur high losses and prohibitive costs. Generating power locally is a suitable alternative, and using renewable energy carriers brings further benefits by attaining energy self-sufficiency. A biomass generation plant using locally available feedstock to produce electricity is an efficient way of providing remote areas with competitive and reliable electricity. A novel micro-scale plant design combining thermochemical and biochemical treatment has been developed. It can provide electricity to a level as small as 50kWe, which fits the size of a remote village. This paper describes the modelling and simulation of the plant design in chemical engineering simulation software. It also covers studies undertaken to address sizing issues, to match domestic demand estimated by load profiles, and operation simulation results. It will be shown that such a system is a feasible and economic solution for reliable and continuous remote power supply.
Keywords: decentralised electricity generation, stand-alone-systems, micro-scale, gasification, anaerobic digestion, microturbine.

1 INTRODUCTION

Matching demand for electricity in remote areas currently means setting up a grid connection. As this can become costly and prohibitive especially for smaller customers with low expected demand, local generation could prove an economic alternative. Generation technology using biomass has numerous advantages over other renewable energy sources, such as no intermittency, high regional availability and employing well-known chemical process designs to name but a few. Especially for remote regions, biomass based power generation and supply could therefore be a milestone in achieving energy self sufficiency.

Research into biomass power system design and operation is currently limited to optimising large-scale plants for a base load power supply. Although this approach may be suitable in areas with well-operated network systems, a stable grid connection is not available everywhere. A micro-scale biomass generator suitable to provide sufficient power on a local basis could eventually replace grid connection and current fossil-fuel based generator sets used for power islands. Such a system can prove very beneficial, as remote locations normally have high regional availability of biomass feedstock. However, currently available biomass plant designs are unable to cope with volatility and fluctuating power demand, which has to be expected when meeting local demand.

A novel micro-scale biomass based generation plant has been modelled by the authors. Developed to be operated in remote regions and not depending on a grid connection, this plant can meet local demand and provide power on an ongoing, flexible basis. It uses both main feedstocks normally available, which are wet biomass such as sewage sludge or manure, and dry biomass such as wood.

This paper covers a brief model description and simulation results when running the plant in a way which can cope with load profile patterns.

2 SIMULATION METHODOLOGY

The micro-scale biomass plant designed by the authors combines both thermochemical and biochemical treatment. This plant consists of a simple fixed bed gasification system, and an anaerobic digestion reactor. Both convert biomass feedstock into fuel gas, which runs a microturbine, the power generation part of the plant. The whole design has been described in detail elsewhere [1, 2] and can be scaled to a fitting size for remote villages or farms, whose demand is in the region of 50kW.

The plant design enables flexible operation by adjusting the power output of the generator. It can therefore meet volatile demand patterns, which is crucial for local generation.

Another focus was laid on choosing robust technology and ensuring long maintenance cycles to enable the design to be operated in remote areas.

The general design of the plant and its main parts are shown in the process flowchart in Figure 1.

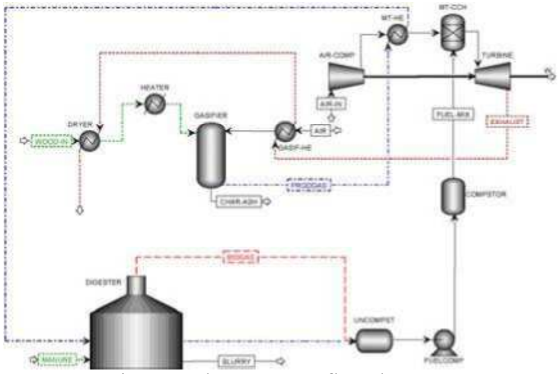

Figure 1: Biomass plant process flowchart

A detailed simulation model of this plant has been set up in chemical engineering software. The plant was modelled using the Aspen Plus environment, which provides a large number of chemical models for each of the main parts of the unit. The methodology of modelling has been described in a separate publication elsewhere [3], however its main conversion and generation parts are briefly described in the following section.

2.1 Dry feedstock conversion - Gasifier

Woody biomass is a complex mixture of a large number of different organic molecules and can hardly be modelled as a conventional chemical substance. However, it can be described by means of its proximate and ultimate analysis, using values from literature [4-6]. As those properties only vary very little between different feedstocks, they can be assumed to be constant.

The biomass molecules mainly contain carbon, hydrogen and oxygen atoms, as well as minor nitrogen and sulphur residues. Inside the fixed bed gasification reactor, they are decomposed by partial oxidation. Air is used as the gasification medium, after being preheated in a heat exchanger. The preheated airstream and the biomass stream are converted into producer gas, a gas mainly consisting of nitrogen, carbon monoxide, hydrogen and carbon dioxide.

This process is modelled using the ‘Minimisation of Gibb’s Free Energy’ approach [7]. The Gibb’s free energy of a system is the thermodynamic potential which measures the maximum amount of non-expansion work available from a system. It is defined as

$$G = H - TS \quad (1)$$

For changes of a system, such as chemical reactions, a negative difference in Gibb’s free energy between the initial and the final state results in the chemical reactions being favourable and thus likely to happen. It can be expressed as

$$\Delta G = G_2 - G_1 < 0 \quad (2)$$

Using the ‘Minimisation of Gibb’s Free Energy’ approach for modelling chemical reactions therefore provides information about which reactions will influence the system in the most thermodynamically favourable way.

Modelling a fixed-bed gasification system with the Gibb’s approach and assuming chemical equilibrium are an appropriate way of simulation and provide realistic results, as has been mentioned in literature [8, 9].

2.2. Wet feedstock conversion - Anaerobic digester

Anaerobic digestion (AD) is a well-known process employed in farming and waste water treatment industry for decades to treat sewage sludge or farming manures. The underlying chemical reactions form a very complex process, as a large number of microbial conversion steps happen consecutively and/or simultaneously. The wet feedstock is decomposed and biogas is formed, which is a mixture of two main components: 60% methane and 40% carbon dioxide. Additionally, water vapour and hydrosulphide can be found in traces [4, 10].

Accordingly, the AD model in this study calculates that a certain amount of biomass feedstock is converted into biogas inside the digester tank, while the remaining components are unconverted biomass and microbial cells, which form the slurry stream exiting the reactor.

AD processes, due to the microbial reactions and the growing of microorganisms during biogas production, are comparably slow and therefore need to be continuous. Manure needs to remain in the reactor for a long period of time, in general around 20 days. The digester model acknowledges this and for a manure intake of 11ton/day, a total tank size of around 200m^3 can be estimated. 1/20 of this volume is replaced each day by new manure, while the remaining manure needs to be kept at the temperature range suitable for AD processes to take place.

This however means that heat losses from the tank to the surrounding environment occur, which have to be accounted for, especially during the long periods of operation. The total heat demand of the AD reactor consists of the heat losses of the tank and the heat to warm up new manure from ambient to the temperature range of 35°C, at which conversion reactions occur. It can be described as

$$Q_{AD} = Q_{loss} + Q_{warm} \quad (3)$$

The heat losses from the reactor to its surroundings are calculated using Newton’s law of cooling, with an overall heat transfer coefficient based on own calculations and available literature [11, 12]:

$$Q_{loss} = UA(T_d - T_{amb}) \quad (4)$$

The heat demand to bring the new manure to the reactor temperature follows an equal approach:

$$Q_{warm} = mc(T_d - T_{amb}) \quad (5)$$

2.3. Power Generation - Microturbine

A microturbine has been chosen as the generation unit of the plant. Microturbines are aeroderivative turbines and consist of an air compressor, air preheater, a combustion chamber and an expansion turbine. The turbine and the compressor are mounted on the same shaft, and the available net shaft work can be calculated as

$$W_{avail} = W_{shaft} - W_{compr} \quad (6)$$

The microturbine model employed in this study follows this basic structure. In the first step, an ambient air stream is compressed to a pressure of 3.35bar. It is then preheated using the producer gas exhaust heat in the microturbine heat exchanger. Afterwards, it enters the combustion chamber, where it burns the compressed producer gas/biogas mixture from the fuel storage. The high pressure exhaust stream is finally expanded to atmospheric discharge pressure in the turbine.

All turbine performance parameters in the model follow microturbine specifications as mentioned in [13, 14].

2.4. Gas storage system, feedstock pre-treatment and power sink

The fuel gas compressor and storage system forms the capacity storage within the plant. Both gasification and AD are continuous processes and cannot be adjusted quickly. Therefore, by storing sufficient amounts of fuel gases, the plant output power level can be changed by flexibly running the microturbine. Hence the gas storage replaces electric storage such as batteries and provides a buffer for volatility of demand.

The producer gas stream from the gasifier is mixed with the biogas stream from the AD, and the combined stream is then compressed to a pressure level of 5bar before being stored. This is necessary as the microturbine requires a minimum energy inflow for operation.

The compressor is modelled based on parameters mentioned in literature [14], and its power requirements are relatively constant, due to the continuous gasification and AD operation.

The feedstock pre-treatment takes place in both the wood dryer and the electric heater, whereas the second also forms the power sink of the plant system.

The microturbine exhaust stream is a high-temperature air stream which can be used in the wood dryer to use its thermal energy and decrease the wood moisture content, which results in a better quality producer gas. It reduces the biomass moisture content from an initial value of 60% for fresh wood biomass [15, 16] to around 10%. This value is further reduced in the electric heater, depending on the amount of power available for this power sink.

The plant will be the single generation unit and has to meet residential or industrial demand. This means that a balance between demand and generation needs to be achieved at each unit of time, as no electricity storage is available.

The microturbine therefore needs to generate at least the amount of power demanded. It however cannot instantly change its output when demand increases; instead, it needs around 20-30s to adjust to a higher or lower power level [17]. This means that the microturbine generation always needs to exceed the demand in order to ensure reliable supply. A logical consequence of this is that a certain amount of power needs to be 'used up' within the system to achieve a match between generation and demand. This amount of 'excess power', which can be calculated as the difference between available turbine power, power demand of the fuel gas compressor and demand,

$$W_{excess} = W_{avail} - W_{gascompr} - W_{demand} \qquad (7)$$

will be used in the electric heater to further decrease the biomass moisture content.

3 SIMULATION RESULTS

The results from running the gasification and AD model show close comparison to literature values from similar projects. The generation part of the plant has been checked and was able to use the fuel gas for power generation. Scaling simulations were undertaken in order to find out about sizing limitations and correlations between feedstock input and gas output. Those results will be described below and show that the plant operation is both feasible and realistic.

In a second step, ongoing plant operation was simulated. By using domestic load profiles from [18], it was tested whether the plant can be run in order to mirror the load patterns and thus provide ongoing power supply.

3.1 Plant scaling, gas production and generation rates

One main intention of the plant design was incorporating efficient internal heat management. In order to check suitable plant scaling alternatives, the raw feedstock inputs have been varied. As the heat streams of the two conversion subsystems are connected to each other, a certain correlation between wood and manure intake will lead to the most efficient process. This correlation has been found by varying the feedstock, and the result of this optimisation is shown in Table I. Based on this, the producer gas and biogas production rates are drawn over the feedstock intake in Figure 2. Finally, based on the use of the produced fuel gas, Table I also shows the overall available power.

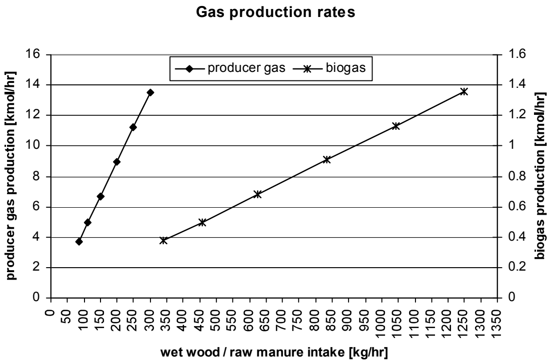

Figure 2: Producer gas and biogas production rates

A wet wood intake of 112.5kg/hr and a manure intake of 11t/day have been chosen as the base case, called 'B1' in Table I. They were found as the minimum size of the plant system. When trying to further decrease the size of the system, the heat losses in the AD increase to a level which cannot be compensated by the internal heat usage anymore. With falling digester size, the heat losses from the reactor to its surroundings raise in proportion to its total heat demand. They already reach more than 50% of the total AD heat demand for the base case B1. The AD heat demand is provided by the producer gas, which leaves the gasifier at a temperature of around 750°C. When decreasing the gasifier size, less producer gas is available, and thus the AD heat demand exceeds the heat available when scaling to lower intake levels than used in B1.

Table I: Feedstock Intake and Resulting Power Generation

Case name	Woody intake [kg/hr]	Manure intake [t/d]	Net power [kW]
B1 (base case)	112.5	11	60.418
B2	150	15	80.541
B3	200	20	106.732
B4	250	25	132.449
B5	300	30	157.924

It can be seen in Table I that the net system power, which is the available turbine shaft power less the constant fuel gas compressor power, has a range of 60-160kWe. Given the average individual domestic demand obtained from the load profiles used, this would translate into a group of ca. 50-150 dwellings. Alternatively, industrial demand of similar size could be supplied with this design.

The base case raw feedstock intake 11t/day of manure would translate into a cattle herd of 100 cows [19], and the intake of 112.5kg/hr of wet wood should not provide obstacles for a remote area, as plenty of woody biomass is normally available in such locations. Therefore, the base case can provide a small village with locally sourced power.

3.2 Load mirroring operation

In order to understand whether the system can provide ongoing power supply, domestic load profiles were used to understand the patterns in demand and to evaluate fluctuations which need to be expected. The load profiles used were domestic 5min interval profiles, differentiated into weekday and weekend and into summer, winter and shoulder season. A more detailed description can be found in [18].

As the microturbine needs around 20-30s to adopt a higher or lower power level, it will not be able to instantly follow load changes. Therefore, the turbine will generate an amount of power which is above the demand, and the 'excess' power is diverted to the fuel compressor and the electric heater. In a first step, the load profiles have been adjusted to represent the demand of 120 dwellings, and this profile was then rounded up to the next multiple of 5kWe. The difference between the actual amount and this rounded demand forms part of the excess electricity to be consumed by the power sinks.

Both a winter weekday and a summer weekend case were investigated for this study, as they provide the two extreme cases. Demand is on its highest level during the winter weekday, and falls to its lowest levels during summer weekends. The winter weekday demand curve is shown in Figure 3, and the volatility of demand can clearly be seen: the demand finds its minimum during the night with around 25kW, before a first peak in the morning hours occurs. After a comparatively steady demand during the day, the main peak can be seen in the evening, where up to a maximum of 85kW are demanded, before decreasing in the late evening back to the night level.

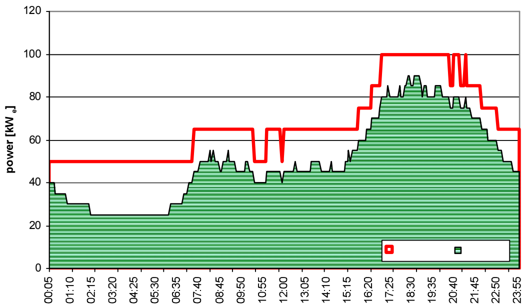

Figure 3: Generation and demand on a winter weekday load profile

Similarly, the generation and demand patterns for the summer weekend case are shown in Figure 4. Compared to the winter weekday case, two main differences occur. Firstly, the absolute level of demand is significantly lower, its maximum peak level decreases from 85kW to 60kW. Secondly, whilst the peak is very distinct for the weekday pattern, the weekend profile shows a comparably constant demand during the day. However, night demand is still considerably lower.

To meet the demand with the microturbine, it was chosen to fix the generation to five load steps: full nominal load, half nominal load and three intermediate stages. This means that the turbine will only be allowed to have those five output levels, and that it will continuously run with at least 50% of its nominal power. This has been mentioned as a minimum level for maintaining both acceptable turbine efficiency and steady and smooth operation [20].

For the cases discussed and the generation pattern described, the turbine will generate 50kWe, 65kWe, 75kWe, 85kWe or 100kWe, as shown in Figure 3 and 4 with the thick red generation curve. Depending on the load, the turbine will be set to its respective output level, and by using a buffer algorithm, the demand will always be met.

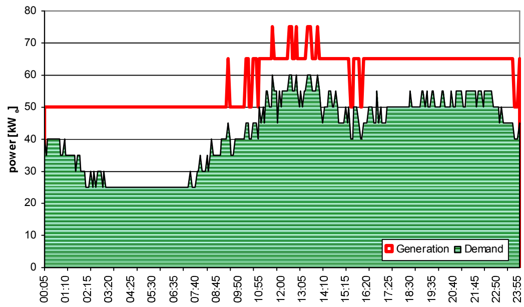

Figure 4: Generation and demand on a summer weekend load profile

When comparing the generation curves in Figure 3 and 4 with the net power level of the base case B1 in Table I, one can find that the maximum power levels are different; in Table I, the net available power is mentioned as 60kWe, whereas in Figure 3, a maximum level of 100kWe occurs. This results from the fact that Table I shows the turbine output assuming a flat generation during the whole day and including the fuel gas compressor power, whilst the graphs show the variable power output depending on the load.

In order to compress the continuously produced fuel gas, the fuel compressor needs around 15kWe. However, the fuel gas compressor can either be operated constantly on a fixed power level, or it can be operated on variable power, depending on the amount of power available. In times of low demand such as during the night, even running the microturbine on half its nominal load results in a massive over-generation, whereas during peak demand, the turbine is hardly able to provide sufficient power when the compressor demand needs to be met as well.

Instead of facing these problems with a larger turbine, the authors have decided to uncouple the fuel gas compressor from the steady operation of the gasifier and AD. Produced gas will first be stored in an intermediate uncompressed storage, and will be compressed when sufficient power can be diverted from the turbine. Once compressed, it will then be stored in a compressed gas storage, from which it can be discharged timely and fed into the turbine, in order to adjust its power output.

This uncoupling of the fuel compressor results in two major benefits of the whole plant system: the fuel gas can be compressed during non-critical times, and the fuel compressor can be operated on different power levels, which result from the difference between generation and demand.

This compressor operation pattern is indirectly shown in Figures 3 and 4 as the difference between the generation and the demand curve, as this is the amount of power available for the compressor. It therefore runs on various power levels from less than 10kWe to more than 30kWe. During the evening peak times, when the turbine runs on full load to meet demand, the compressor will not operate at all, and during times of low demand, the compressor will run on up to 30kWe of unused turbine power.

This operational cycle can be implemented successfully, as long as over a longer overall period, such as a day, the compressor receives sufficient power to compress the whole gas produced during that day. Graphically, this means that the area between the lines in Figures 3 and 4 needs to be of a certain size, equivalent to the compressor being operated on 15kWe flat power for 24 hours continuously.

Additionally, the compressed fuel gas storage needs to provide sufficient compressed gas for the turbine to run, even when the compressor is not providing sufficient compressed gas. Similarly, an uncompressed storage needs to provide sufficient uncompressed gas for the fuel compressor in times of high levels of compressor power, as conversion remains constant and will be lower than this volume. However, both issues can be addressed with ease by sizing the storages sufficiently.

By uncoupling the fuel compressor, the plant system is able to provide power in a reliable way and on an ongoing basis. Although it necessitates both uncompressed and compressed gas storages, the benefits that this operation provides for the whole system exceed the costs of these storages, especially due to its relatively low costs.

A final analysis has been undertaken in order to understand the charge and discharge patterns of such a fuel system. As discussed, production of the fuel gas will be continuously, in order for the gasification and AD processed to remain stable. In contrast to that, the generation follows a certain pattern during the day, which means that in times of high demand, the microturbine needs more fuel gas to reach its full nominal power output, whereas during low demand periods, the turbine will require a smaller amount of fuel gas when running on half load. Therefore, both the storage charge and discharge cycles as well as the absolute storage levels are shown in Figure 5 for the winter weekday and in Figure 6 for the summer weekend case.

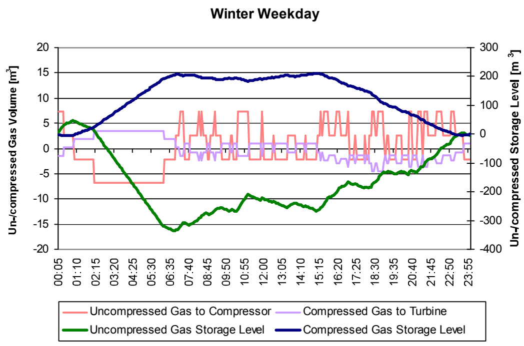

Figure 5: Winter weekday absolute storage levels and charge/discharge cycles

The gas production rate remains constant during the whole cycle of one day. This total amount of gas produced during the one-day interval equals the amount of gas necessary to run the turbine in order to meet the demand for the day. This follows from the fact that the size of the plant and the size of the group of dwellings it is supposed to supply with electricity need to match. As the winter weekday case is the case with the highest absolute demand, the storage levels for this case will return to zero at the end of the one-day period.

In contrast to that, for the summer weekend case, overall generation is below the winter weekday levels, thus for the whole day, the microturbine generates a lower amount of power. As gas production rates remain the same, this means that a certain amount of gas will not be used by the microturbine. The fuel compressor power remains the same, therefore all produced gas is compressed and the uncompressed storage level equals to zero. However, as the microturbine needs less gas, the compressed gas storage level does not equal to zero at the end of the one-day period, and a certain amount of gas remains in the storage.

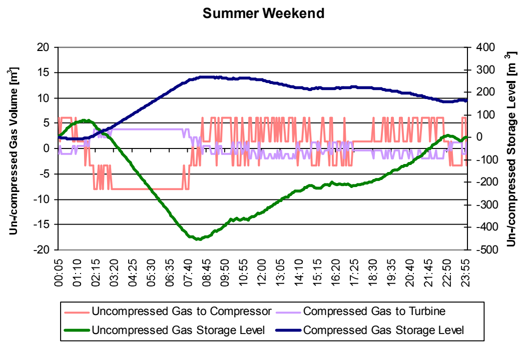

Figure 6: Summer weekend absolute storage levels and charge/discharge cycles

The actual amount of compressed gas required by the microturbine is shown in Figures 5 and 6 as the violet 'Compressed Gas to Turbine' curve. The amount of uncompressed fuel gas that is led to the fuel compressor is shown as the coral 'Uncompressed Gas to Compressor' line. It can be seen that the turbine gas demand exceeds compression during the evening peaks, thus the values turn negative, i.e. the compressed gas storage is discharged. In contrast to that, the fuel compressor throughput exceeds the turbine demand during the night period, hence the values turn positive. A mirrored pattern occurs for the coral line for the compressor: During the night, the compressor operates on its highest power levels and thus compresses more gas than being produced, so the uncompressed gas storage is discharged. In contrast to that, during the peaks the compressor is set to low power and more gas is produced than being compressed, thus it is charged to the uncompressed gas storage.

Given the total level of both storages and the daily gas production rate, it can be calculated that storages will need to be sized to between 20 and 30% of the daily production for the different cases, which is on an acceptable level. The system will therefore always be able to provide the amount of fuel needed by the turbine in order to meet the load in time.

3.3 Ongoing plant operation

Evaluating the demand and generation patterns as done above reveals information on whether the plant system is able to cope with total load levels and with fluctuations in demand during the course of a day. It has been shown that the plant can be operated to match demand by applying storages of an acceptable size. Analysing the storage levels, information was revealed for the plant operation of a one-day period, however especially for the shoulder and summer period, it is essential to analyse ongoing plant operation and performance.

Over longer periods such as one month, the demand patterns will follow a scheme of alternating weekdays and weekends. The plant generation patterns will also follow this scheme accordingly, and weekday and weekend demand patterns will alternate. As shown above, generation and demand are levelled out during the course of one day, which means that ongoing generation can be obtained by applying this pattern, and the plant operation can be automatically adjusted to the season and to whether each day is a weekday or weekend.

The storage levels however show a different pattern. As described, the total amount of power available for the fuel compressor during the period of one day equals the amount of power necessary to compress the total gas production volume of that day. This means that for all seasons, the uncompressed storage level will return to the initial level at the beginning of the one-day period. Therefore, sizing issues of the uncompressed storage can be addressed by analysing the individual daily load profiles and optimising the storage.

In contrast to that, the uncompressed storage level only returns to its initial value in the winter period, as the gas production equal the demand of gas for generation. During the shoulder and summer period, some gas will not be needed by the microturbine as overall generation is lower. This however results in an increasing storage level for the compressed storage when running the generation plant continuously. At the end of each day, a certain amount of excess gas will remain in the storage, therefore this level continues to increase. This is shown in Figure 7, which provides storage levels for both the uncompressed and the compressed gas storage for the three seasons and a randomly chosen 30-day interval (1-5 being weekdays and 6, 7 being weekends).

The uncompressed gas storage levels (red line) fluctuate around the zero value during each day of the discussed period, however they do not significantly increase over time and remain at the daily values discussed above. As can be seen, for the compressed gas storage levels (blue line) this is just true for the winter season. Only in this season, the absolute storage level returns to its initial value, whilst for the other two seasons, the storage level increases continuously.

There are two main alternatives to handle this situation. Either the plant design is changed accordingly and gas production rates are decreased, or the excess gas is used alternatively. The first possibility however was found to not be suitable. The plant design employs high levels of internal heat stream usage, as described above. It was found that the level discussed in the base case scenario is on the minimum border of feasibility, which means that for further decreasing the ratio between the main conversion and generation units, feasibility problems will occur. The hot producer gas stream for example is used in heat exchangers, and if the plant system is minimised further, the streams will not be able to provide sufficient heat any more. Therefore, it was decided to not adjust the gas production rates and to accept the fact that excess gas will be produced.

The second possibility and the chosen alternative is to use this excess gas. For the shoulder and summer season, the amount of excess gas accounts for 10-16% of the daily production. For a whole calendar year and the distribution of days to each of the six profiles, an excess gas production of 8.2% of the total gas production can be calculated.

This amount of gas should therefore be used to provide a sufficient reserve in case of outages of the conversion units or in case of demand for higher generation. Using part of the excess gas as a security of supply means that in case of faults within the gas production units, the microturbine will still be able to provide power to meet the demand. Additionally, using part of the excess gas to be prepared for higher temporary loads such as during construction or similar activities and then being able to generate above the generation patterns described will also enhance the plant flexibility.

In case neither of those two occur and to prevent storage levels exceeding the limits, the excess gas can still be flared off. The authors are aware that this design will impact the overall plant efficiency to some extent, however it was chosen to focus on the flexibility and reliability of supply and thus accept that under some circumstances fuel gas may not be used. However, as the overall excess gas rate lies below 10%, it provides an acceptable level for such measures.

4 DISCUSSION AND CONCLUSIONS

This paper marks the way to a new idea of generating power. Instead of employing large scale generation plants and using grid technology to reach customers, the authors have designed a plant solution that can meet demand locally. By combining well-known biomass-based conversion technology to a micro-scale generation plant, fossil fuel dependency can be overcome. Instead, locally sourced and highly available feedstock can be converted into renewable energy and provide an off-grid solution for small customers that otherwise may not have the benefit of a secure and stable grid connection.

The author's novel combined feedstock plant employs gasification and anaerobic digestion technology to convert feedstock into a biofuel, and microturbine technology to generate power. It can provide electricity on an ongoing basis and can be scaled to levels of 50kWe.

A detailed and conservatively designed plant model and extensive simulations have been undertaken in Aspen Plus, a standard software environment for chemical process simulations. The simulations provide realistic results of the plant operation when compared to literature values and have proven the feasibility of the plant.

By using domestic load profiles, it was demonstrated that the plant operation can follow load patterns and that it can be a reliable single source for electricity. High load fluctuations, which have to be expected in an off-grid application for domestic or small industrial customers, were accommodated by the plant without major problems or obstacles. This was achieved without the need of large scale electrical storage, and thus avoids all ecological and economical implications of battery or other electrical storage. Instead, cheap and reliable gas storage facilities provide sufficient capacity.

By using these intermediate fuel storages as a buffer, this plant design has proven to be able to cope with load fluctuations by adopting different output levels. Steady plant generation can be achieved by adopting a simple control algorithm, and storage sizing issues were addressed successfully. Matching demand and supply at each instant of time can be achieved by generating excess electricity and employing a power sink within the process to consume this excess power.

This plant design provides a number of major novel approaches in rural electricity provision and in applying renewable energy sources, and further simulation studies to be undertaken will reveal more of its potential.

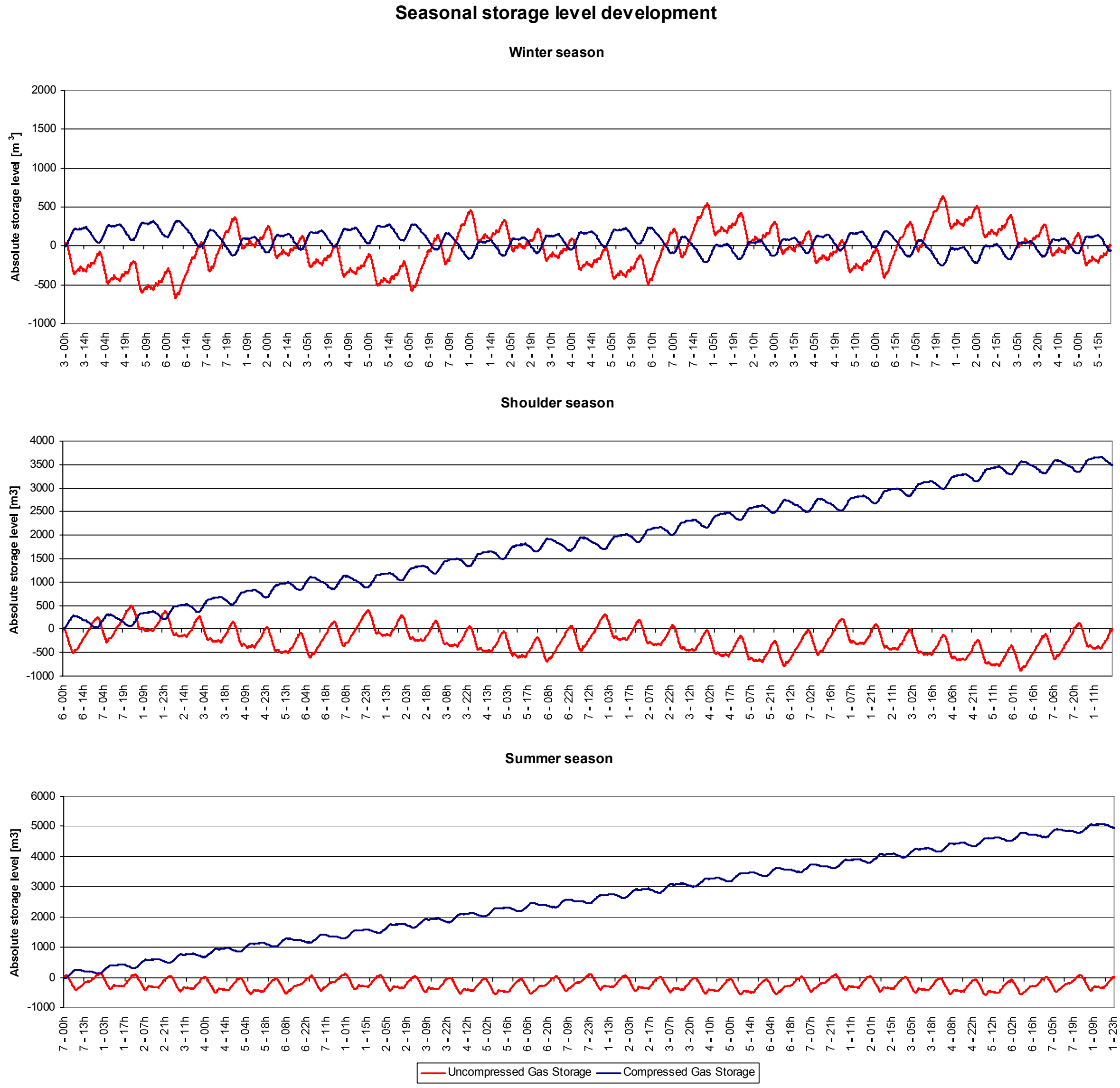

Figure 7: Seasonal storage level development for a one-month period

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Overview of Biomass Conversion and Generation Technologies

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***Abstract*-- The total energy stored in terrestrial biomass outnumbers the annual world energy consumption by a factor of more than fifty. Being highly available, renewable and geographically dispersed, biomass can form a substantial part of future energy sources and biomass-derived energy generation can result in both CO_2-neutral and stable long-term energy supply for most areas in the world. Having a relatively low energy density, biomass processing in decentralised plants seems best suited to minimise transport cost of both the raw material and the products. To facilitate a wide-spread use of decentralised plants, their design has to be simple and they need to be easy-to-operate and flexible.**

This paper covers the two sequential steps of biomass power: conversion technologies to transform the raw feedstock into suitable intermediate energy carriers, and generation technologies to gain energy in the form of heat and/or electric power. A broad number of conversion technologies currently exist for both wet and dry biomass, ranging from research-stage up to commercialisation.

In this paper the main ways of converting dry as well as wet feedstock will be discussed: combustion, gasification, pyrolysis and liquefaction for the further and fermentation and anaerobic digestion for the latter. Additionally, the common generation technologies will be analysed: internal combustion engines, stirling engines and internally- and externally fired microturbines.

Finally it will be recommended which technologies to use to meet a substantial part of the future energy demand on the basis of biomass in micro- or small-scale applications.

***Keywords*-- biomass, micro-scale applications, decentralised generation, stand-alone-systems**

I. INTRODUCTION

Biomass, being defined as all organic matter such as wood and wood waste, agricultural residues and farming manure [1, 2], is one of the most wide-spread energy resources worldwide. Its high availability and dispersed location enable it to be used for decentralised power generation. Due to being renewable, a long-term energy supply on the basis of biomass can emerge. While its low energy density could be seen as a potential barrier for implementation, when using biomass in small- and micro-scale applications these shortfalls can be overcome and it can even substitute grid connection for remotely located customers with sufficient amounts of feedstock on site [3].

This paper discusses common biomass process technologies to be able to evaluate those worth for employment in micro-scale plants. Therefore, a short technology review is followed by a relative comparison and performance ranking to finally conclude with a recommendation about which technologies to use.

II. CONVERSION TECHNOLOGIES

Biomass in general is divided into wet and dry feedstock, the first with a moisture content of significantly less than 50%, and the latter with up to more than 90% for animal manures [4]. Wet biomass is normally treated biochemically, whereas dry biomass is processed thermochemically. In both ways, an intermediate fuel is produced to be used for generation purposes. Extensive and detailed conversion technology descriptions can be found in literature, thus this section will only provide a compact overview of suitable conversion technologies, divided into thermochemical and biochemical.

A. Thermochemical conversion

Four main conversion technologies have emerged for treating dry biomass: combustion to immediately release its thermal energy and gasification, pyrolysis and liquefaction to produce an intermediate liquid or gaseous energy carrier. Aside from the low efficiency of common combustion equipment, its immediate energy release results in low flexibility [5-7], so it is less suited for flexibly running energy systems.

Instead, gasification as the substochiometrical oxidation of biomass with air or steam as gasification agents seems more promising [2, 7]. Several reactor designs from simple fixed bed to fluidized bed or entrained flow reactors have been investigated and several commercial applications exist [8]. The process temperature level of around 800-1000°C can be achieved by combusting part of the feedstock or by applying internal process heat cycles [2, 6]. The main product of gasification is producer gas with a calorific value of 4-6MJ/Nm^3 using air and/or steam. It consists mainly of CO, H_2, CH_4 and CO_2 and can be stored to be used when needed [9].

Pyrolysis is the heating of biomass in the absence of oxygen and results in char, bio-oil and pyrolysis gas in varying yields, depending on a range of parameters such as heating rate, temperature level, particle size and retention time [2, 7, 10]. The advantage of being able to receive a 'tailor-made' product range competes with the disadvantage of lower yields due to the normally lower temperature range of around 300-500°C [6]. Fast and flash pyrolysis achieve higher yields, however their requirements regarding heating rate and particle pre-treatment are advanced. In general, pyrolysis has not reached full commercial status yet and further needs for development are mentioned [2, 7].

Liquefaction is the low-temperature cracking of biomass molecules due to high pressure and results in a liquid diluted fuel. The advantage of this process, employing only low temperatures of around 200-400°C, has to compete with comparably low yields and extensive equipment prerequisites to provide the pressure levels needed (50-200bar) [6, 11]. Therefore, current interest in liquefaction is low and it is regarded as the least developed conversion technology [6, 11].

B. Biochemical conversion

Wet biomass can be processed in two main ways: by fermenting the feedstock, using yeasts to convert the contained sugar into ethanol. This produces a diluted alcohol which then needs to be distilled and thus suffers from a lower overall process performance and high plant cost [12, 13].

In comparison to that, anaerobic digestion (AD) employs bacteria to transform the organic matter into gaseous products. It shows better economics and numerous applications are operating [14, 15]. The biogas produced has a calorific value of around 20-25MJ/Nm^3 [16] with a methane content varying between 45-75% and the remainder of CO_2, the ratio depending on a number of factors such as retention time, the digester pH value and the temperature level, to name but a few [13, 17]. Three process temperature levels exist: around 15°C for psychrophilic, 35°C for mesophilic and 55°C for thermophilic bacteria. Those low temperatures and the comparably simple digester design, basically a plug-flow or steady-flow stirred tank, are further advantages of AD when compared to fermentation.

III. GENERATION TECHNOLOGY

The intermediate fuel produced in the conversion section of a biomass plant will be used to supply electrical energy in a generation engine. Four main types of engines can be used for the desired size range: internal combustion engines (ICE) and microturbines (MT) as fuel-fired technologies, as well as stirling engines and externally fired microturbines (EFGT) as indirectly fired engines, employing high temperature heat exchangers between the combustion chamber and the working medium. Fuel cells are still in an early stage of development and due to their very high cost seem to not be a viable option [18].

Important parameters for choosing an engine for a biomass plant are its electrical efficiency, as well as maintenance efforts and investment costs. Especially for remotely located applications, robust and durable components are needed to maximise availability and minimise repair and maintenance time. Additionally, when desiring a stand-alone application, the generation part of the plant needs to have a fast response performance for varying loads.

In general, ICEs have the highest nominal (at full power) electrical efficiency of the engines covered in this paper, with around 30-40% [19-21], closely followed by microturbines which lay in the range of 25-35% [18, 21]. Stirling engines and EFGT applications, using external combustion and heat exchangers, can only provide lower efficiencies of around 20-25% [18, 21-23].

Especially when running in stand-alone mode, part-load behaviour becomes a key indicator for an engine's suitability: the optimal engine should immediately correspond to load changes and remain a high efficiency. Several experiments on part-load behaviour have shown that ICE again provide a slightly better part load efficiency than microturbines [18, 24]. In comparison to that, stirling engine and EFGT part load efficiency seems to decrease more significantly, although only few results have been published so far [22, 25, 26].

Discussing maintenance efforts and interval cycles, it can be stated that microturbines and stirling engines are significantly easier to maintain. Both technologies can run up to 10,000-15,000hrs continuously and normally need only one day of maintenance per year [22, 27, 28]. In comparison to that, conventional reciprocal engines need significantly more maintenance, and especially in bio-applications their oil lubrication suffers from the solubility of H_2S and they require frequent oil changes of up to every 500 hours of operation [18, 27, 28], which strongly limits their suitability for remote areas without skilled personnel.

Discussing investment costs of the different engines, a clear tendency towards ICE can be found, followed by microturbines and EFGT. Stirling engines are still significantly more expensive [18, 21]. However, it should be taken into consideration that the latter three are still relatively new technologies which cannot provide the economies of scales of several decades of ICE manufacturing yet, and that, at least for microturbines, the market just recently started to become more mature and decreasing prices seem likely.

The findings of the above discussion are summarised in Table I in a comparative way. This ranking shows a tendency towards microturbines, despite their higher investment cost and because of their significantly better maintenance and operation behaviour.

Additionally, more efficient heat cycles and by that a higher total plant efficiency can be implemented when using microturbines with their high exhaust gas temperature levels of around 300-500°C, compared to only around 100°C for reciprocating engines [16, 18, 26, 29].

TABLE I
GENERATION TECHNOLOGY COMPARATIVE RANKING

Category	Technology			
	Stirling	EFGT	MT	ICE
Full efficiency	--	--	+	+++
Part efficiency	--	--	+	+++
Load flexibility	-	-	++	++
Investment cost	---	--	-	+++
Maintenance efforts	++	++	+++	---
Emission levels	++	++	+++	---
Level of development	+	++	++	+++

IV. CURRENT PLANT DESIGNS

Before suggesting a small-scale plant design being able to cope with the stand-alone requirements, this chapter covers current market deployment of biomass energy plants and shows which applications are available at the desired scale.

For the treatment of dry biomass, predominantly gasification-based plants are employed. Most are connected to ICE [30, 31], whereas fewer use MT technology [31, 32] or stirling engines [3, 31]. Gasifier reactor designs are predominantly atmospheric co- and counter-current fixed bed, and only very rarely fluidised bed or pressurised reactors [30, 32, 33]. Broad varieties of feedstock in terms of size and moisture content have successfully been processed, however varying gas qualities and producer gas tar amounts are mentioned as problems causing downtime.

The producer gas is normally not stored, but directly burnt in the encompassing engine to generate electricity. The use of combined heat and power (CHP) designs is common, which means that the process heat is used for hot water supply, sometimes also to provide heating within the process; the electricity generated is regarded as a surplus and will either be used or exported to the grid. Most plants are thus run in a heat-driven operation mode, its output depending on the heat demand of the customer and the electricity needs supplied by either the plant or the grid [34].

For wet biomass treatment, AD plants are dominating the market. They are predominantly used on farms to process cattle, pig or chicken manure or vegetable wastes. Most plants are in the range of 50-200kW$_e$ and employ mesophilic temperature ranges with rather long retention times of around 15-20 days [14, 27]. Some advanced reactor designs are used as well, including filter technology [35] or a combination of thermophilic and mesophilic reactors [15, 36]. The generation engines coupled with the digester are predominantly ICE and microturbines, and similar to gasification plants, they are mostly run on steady state grid-connected mode to mainly supply heat to the farms and to cover their electricity demand with grid support.

V. CONCLUSION AND OUTLOOK

Gasification and anaerobic digestion as biomass conversion technologies seem probable for the intended scale of 5-50kW$_e$. When considering potential customers for those small-scale applications, a major focus should be laid on farms. They typically can provide large amounts of waste which can be used as biomass feedstock, and due to their often remote location the development of grid-independent energy supply becomes a viable alternative to save installation and maintenance cost incurring with a grid connection.

A farm normally undertakes both livestock management and plant cultivation, so both wet and dry feedstock will be available. Thus a combination of thermochemical and biochemical treatment to be able to use both feedstocks is a way to significantly increase the fuel output. Additionally, designs including both high- and low-temperature conversion processes allow a more efficient internal handling of process heat and by that increase the total plant efficiency.

Our hybrid plant proposal, consisting of a co-current fixed-bed gasifier and a thermophilic anaerobic digester, will best be able to provide an efficient waste management system for the customer and to produce considerable amounts of biogas and producer gas. These gases are then used to provide electricity by employing a microturbine, which has been chosen due to its advantages of long maintenance cycles and good response to load changes. Additionally, a microturbine can be operated autonomously by remote or preset control and thus shows distinct advantages for deployment in remote areas over long periods of time.

The proposed plant will be required to continuously cover the electrical load demand of the customer, which is the electricity need of farm houses and adjacent buildings. As a result, a highly transient and fluctuating load demand curve is expected.

Existing plants are designed to operate as base load applications with a grid connection used to import or export the difference between the consumption and the production of power. Stand-alone or island applications employ large batteries to instantly cover the load change and to allow sufficient time to change the generation output of the engine, however resulting in high costs and losses.

Our proposed plant will be designed to run on a comparably steady load which will always cover the load demand and hence result in a surplus of electricity generation. An electricity sink in the form of an electric feedstock heater will be used, which in fact will result in better conversion efficiencies due to drier feedstock. Thus more intermediate fuel gas will be produced, which can then be stored. This design seems to be more effective than trying to mirror the load demand with the generation output and covering the transition interval with electricity storage. Additionally, this system control will allow the generation part of the plant to run on higher load levels and thus significantly higher efficiencies.

In general, heat demands of the customer are significantly lower than the process heat output. Most CHP applications thus try to enhance the use of excessive process heat by supplying hot water to the customer, however times of high electricity demand do not always cohere with times of high heat demand and thus not all heat can be used productively. Therefore, we aim for a high level of internal usage of the process heat.

Our hybrid plant proposal has been found to be a promising project to supply electricity to remote customers and overcome grid-dependency in the long term.

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MICRO-SCALE BIOMASS GENERATION PLANT TECHNOLOGY: STAND-ALONE DESIGNS FOR REMOTE CUSTOMERS

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ABSTRACT: Given the importance of biomass as a source of power generation and the often dispersed location of suitable feedstock material, small-scale biomass plants have become a very promising field of research. For load demands of 5-50kW$_e$, a flexible and easily operated biomass unit would provide a viable source of energy for areas where grid connection is either expensive or prone to disconnection.
This paper describes conversion and generation technology for current micro-scale biomass plant designs. Most applications handle either wet or dry biomass, but since both feedstocks are often available, this paper suggests a combination of thermochemical and supplemental biochemical conversions to create considerable amounts of fuel and hence electrical capacity.
Discussing the generation part of current plants, a tendency towards using combustion-based technology has been found, while microturbines can provide usable exhaust heat streams and offer better maintenance and operation flexibility. This paper ranks power generation technologies used in current biomass plants in terms of efficiency and flexibility as well as maintenance and economic aspects.
For remote locations without the opportunity of a secure grid connection, the proposed plant design demonstrates a very promising way of supplying future energy needs in terms of both electrical and thermal energy.
Keywords: micro-scale applications, decentralised electricity generation, stand-alone-systems

1 INTRODUCTION

The chemical energy amount stored in terrestrial biomass has been estimated to 25.000EJ. Given the respective 2002 annual world primary energy consumption of 450EJ, it becomes obvious that biomass is an interesting option to supply future energy demands [1]. Although not all biomass can and will ever be used to produce energy, only a small fraction of it can provide a substantial supply of energy to the world. In addition to being renewable and carbon-dioxide-neutral, biomass is comparably easy to convert and to handle and therefore not only UK and European long-term goals see biomass as one of the main factors of future renewable energy generation [2].

Due to its dispersed location and comparably low energy density, biomass should best be converted locally. It is thus of high interest to design micro- or small-scale plants, to be installed directly in locations with high amounts of biomass feedstock. Ideally, those plants can be used to supply remote customers with energy independent of the grid, which can result in substantial savings when taking transmission losses and grid infrastructure costs into the calculation. However, the issue of supplying highly transient and fluctuating load levels is critical, especially when no or only weak grid connections are available.

In this paper, current biomass conversion and generation technology have been discussed with an emphasis on the applicability to micro-scale plants. Finally, a combined plant design which is able to cope with the issues mentioned is suggested.

2 CONVERSION TECHNOLOGIES

Conversion technologies are employed to produce intermediate energy carriers in both liquid and gaseous form from raw biomass feedstock. The fuel's chemically stored energy can then be released and transformed into heat and/or electrical power using generation technologies. Depending on the moisture content of biomass feedstock, either thermochemical or biochemical conversion technologies can be employed, the first being more suitable for dry feedstock, whereas the latter is better for wet feedstock.

2.1 Thermochemical Conversion

Main thermochemical conversion technologies include the high-temperature partial oxidation of feedstock, a process called gasification, as well as the lower-temperature breaking of biomass macromolecules into smaller molecules in the absence of air, called pyrolysis. Additionally, liquefaction as a low-temperature high-pressure process to convert biomass is included in this category.

2.1.1 Gasification

Gasification is the partial oxidation of solid biomass particles into a producer gas mainly consisting of CO, H_2, CH_4 and CO_2 [3]. Due to the substochiometrical amount of oxygen used in gasification, it can be compared to incomplete combustion. Depending on the oxidation agent, different producer gas calorific value (cv) ranges can be achieved: using air as a gasification agent results in the lowest cv of around 5MJ/Nm^3, whereas the use of pure oxygen or steam result in higher cv levels of 10-12MJ/Nm^3 and 15-20MJ/Nm^3, respectively[1] [3, 5]. Temperature ranges for gasification vary, but are rather high with around 700-1000°C [6-10]. In general, three main gasification steps are involved: First the particle drying process where all water is evaporated from the biomass material. This is followed by the pyrolysis process where the material is broken up into volatiles and a char residue. Finally, in the oxidation zone of the reactor, the volatiles, a mixture of different organic and anorganic compounds, are oxidised by the gasification agent and part of the char is reduced from carbon dioxide and water into hydrogen and carbon monoxide [11].

[1] Compared to those values, the cv of natural gas is still significantly higher: around 44MJ/Nm^3 [4].

Biomass particle size ranges vary, but in general are from around 5cm down to a few mm; the feedstock should preferably be dry due to the heat needed to vaporise the water within the particle, however maximum moisture contents of up to 30-50% were mentioned as suitable [11]. Most gasifiers, especially for larger scale units, are designed and set up for steady state production and, although the feedstock input flow can be varied, will result in a rather steady throughput and hence producer gas output. Startup times for smaller plants of around 10-20min were reported [12, 13], so gasification technology seems to be well-suited for base load applications and a continuous gas output. Also, by using gas storage facilities, a very flexible energy supply system can be designed.

Due to producing a comparably low-calorific gas, pressurised storage of the producer gas seems to be a promising alternative to storing large amounts of uncompressed gas. Thus a producer gas compression unit preceding the gas storage is necessary. An alternative is to employ a pressurised reactor. Pressure ranges of 3-10bar have been reported [14, 15], and the advantage of the latter design is that only the gasification agent needs to be compressed, whereas in the original design a far higher volume of producer gas must be compressed and thus a significant amount of energy input is needed [2, 5, 16]. However, the cost impacts of using pressurised reactor equipment strongly limit the utilisability of such designs.

A broad range of gasification reactor designs has been discussed in literature, and three main categories can be divided, differentiated by the velocity of the gasification agent in relation to the biomass particles: fixed-bed reactors, fluidised bed reactors and entrained flow reactors (e.g. [3, 5, 11]).

In *Fixed-bed Reactors*, the gasification agent velocity is rather low, thus it steadily flows through the biomass particles. This reactor design is comparably simple and cost-competitive and thus is the preferred option for small scale applications. Varying particle sizes as well as varying feedstock quality can be handled so this design is a very interesting option for small scale applications. Two options exist: the design which employs the same flow direction for biomass particles and the gasification agent (co-current or downdraft), whereas the alternative employs the counter-current or updraft flow principle, i.e. biomass particles flowing from top to bottom whereas the gasification agent flows from bottom to top.

The advantages and disadvantages of the co-current design include:

- relatively clean producer gas due to exiting at the reactor bottom directly after conversion of biomass
- high temperature of exiting gas (around 700°C)
- lower mixing intensity resulting in the problem of clogging of biomass particles due to co-current flow, thus higher requirements regarding equal feeding of the particles

The advantages and disadvantages of the counter-current design include:

- intensive mixing of particles and agent due to counter-current flow, resulting in higher conversion rates
- high heat transmission levels from the hot producer gas to the entering biomass particles, thus drying effect of the entering biomass
- relatively cold exiting gas due to the heat transmission
- high amounts of tar in exiting gas due to contact with biomass material entering the system

In general, the co-current design is more interesting for micro-scale applications, and sophisticated gas cleaning equipment can be avoided.

Compared to fixed-bed reactors, *Fluidised-bed Reactors* employ a higher gasification agent velocity and a bed consisting of particles and inert bed material such as sand. The advantages are higher conversion rates due to the better mixing of agent and biomass and better heat transmission from the bed material to the biomass feedstock. However, this design necessitates cyclones to separate bed material and unconverted particles from the exiting producer gas system and loops to re-cycle the bed material into the reactor and thus is only viable for large scale units of greater than 1MW.

Entrained flow Reactors employ an even higher gasification agent velocity and result in an evenly distributed particle/gasification agent stream within the reactor. They result in the highest mixing rates of particles and agent and therefore in very high conversion rates. However, their need to have a high velocity results in rather large designs to ensure long retention times to convert the biomass. The need to accelerate the gasification agent results in higher energy inputs when compared to fixed-bed reactors.

When considering plant sizes, it has been mentioned in numerous reports that a throughput of around 1kg/hr of biomass feedstock can be converted into a gas volume suitable to generate $1kW_e$ output [7, 15, 17-20].

2.1.2 Pyrolysis

Pyrolysis is the conversion of solid or liquid biomass into a mixture of liquid, gaseous and solid intermediate fuels in the absence of air [10]. Therefore, pyrolysis can be seen as either incomplete gasification or one step of the gasification process described above. When biomass particles are pyrolysed, the water amount is vaporised and then the particle is broken up into char and a volatile compound. This volatile portion is then partly cracked into gaseous side-products. The main product of pyrolysis is the liquid phase, called bio-oil, a mixture of a complex range of organic and inorganic compounds diluted in a high amount of water.

Temperature levels for pyrolysis are significantly lower than gasification temperatures and vary around 300-500°C [5, 21-24]. The heat necessary to pyrolyse the feedstock needs to be supplied without introducing oxygen into the reactor, so most pyrolysis processes burn the char residue externally and employ heat exchangers to heat the reactor [25-28]. Alternative designs include a combustion area within the pyrolyser where combustion air is introduced and the char is combusted [29, 30].

One of the main advantages of pyrolysis is the possibility of varying the ratio of the three product categories by varying process parameters. The gaseous phase yield can be increased by high temperatures and long residence times to intensify cracking processes, whereas moderate temperatures and short residence times result in a higher amount of bio-oil by preventing oil cracking. Low temperatures and long residence times predominantly result in char residues. Given those variations, three different pyrolysis processes are classified in literature (e.g. [5, 24, 31, 32]): conventional pyrolysis or carbonisation with low heating rates and temperatures, resulting in higher particle retention times of up to several minutes and char as the main product;

rapid and fast pyrolysis with medium to high temperatures and high heating rates resulting in shorter retention times of several seconds; and finally flash pyrolysis with very high temperatures and heating rates resulting in very short retention times. However, high heating rates correspond with the need for smaller and very uniform feedstock particles to facilitate rapid heating, an effect resulting in very high feedstock prerequisites and thus pre-processing costs.

So far, a broad range of designs have been introduced for both large and small scale applications. Rapid, fast and flash pyrolysis seem more viable for larger scale units due to the high heating rates necessary and the more intensive particle pretreatment, and due to the comparably low gas and oil yields of conventional pyrolysis, only few commercial applications have been found [18, 22, 23]. Another obstacle of pyrolysis is the water dilution of the bio-oil and its corrosivity due to the broad range of organic and inorganic compounds solved. Thus the application of bio-oil for electricity generation technology seems rather difficult [33] and gasification is the preferred option.

2.1.3 Liquefaction

Whereas gasification and pyrolysis mainly produce the intermediate fuel with endothermic chemical reactions and require a certain temperature level, liquefaction tries to cleave the large biomass feedstock macromolecules by applying high pressure and only low levels of heat. Common process parameters are temperatures of around 200-400°C and pressure ranges of 50-200bar [10, 34, 35]. The main products of liquefaction evidently are liquid fuels with a similar consistency of pyrolysis bio-oil. However, oil yields are lower than for pyrolysis processes, and given the very high pressures of the liquefaction reactor and associated equipment, there are only a few examples of commercially available liquefaction processes. Thus liquefaction is in the earliest stage of development anddoes not seem viable for small applications [10, 35].

2.1.4 Thermochemical Conversion Technology Ranking

The following table summarises the findings of the preceding investigations and ranks the applicability of the different thermochemical conversion technologies. Assessments vary from '---' for 'very poor' to '+++' for 'very good'.

Table I: Ranking of thermochemical conversion technologies

	Gasification	Pyrolysis	Liquefaction
conversion level	+++	++	++
simplicity	++	++	---
plant cost	++	++	---
conversion time	+	+	+
applicability to scale	+++	++	--

From this it can be concluded that gasification shows strong indications to be best-suited for thermochemical micro-scale applications.

2.2 Biochemical Conversion

Highly water-diluted biomass such as sludge, manures or vegetable waste can hardly be treated economically in thermochemical conversion reactors due to the energy input necessary to heat the feedstock to the temperature needed for the conversion and to vaporise the water. For feedstock with significantly more than 50% moisture content, it is normally not viable to apply thermochemical conversion technologies. Alternatively, biochemical treatment at comparatively low temperatures becomes a more economic solution. The two main processes are anaerobic digestion (AD), where biomass is converted by bacteria, and fermentation, using yeasts to convert biomass. While AD is the standard solution for treating very high dilution levels, fermentation can also be applied to biomass containing lower amounts of water.

2.2.1 Anaerobic Digestion

Anaerobic digestion as the bacteria-driven conversion of biomass to biogas in the absence of oxygen results in depletion of the biomass' oxygen content for the metabolisms [36]. To achieve this, biomass is filled into a reactor and kept at the respective temperature level needed by the bacteria present. Three different bacteria strains can be categorised, resulting in three main temperature ranges of AD processes: psychrophilic (~15°C), mesophilic (~35°C) and thermophilic (~55°C) [37, 38].

The digestion reactor feedstock is normally fed step-wise (plug-flow) or continuously (steady-flow), and gas production is enhanced by mixing or stirring. Biomass retention times of 10-20days are common, however part of the volume is replaced by new feedstock in intervals [36]. All three AD temperature levels are comparably low and therefore easier to provide, for example by using exhaust heat from generation or other plant processes. In addition, AD plants can cover a wide range of scales as well as feedstock: practically all livestock slurry as well as organic farm wastes and even cellulose-containing material can be treated in AD plants to produce biogas, and by-products of AD are settled fibre usable for soil conditioning and liquid fertilizer which can be used on the farm without additional treatment [33, 36, 39].

In general, around 30-60% of the digestible material is converted into biogas, a mixture of around 45-75% of CH_4 and the remainder of CO_2. The feedstock utilisation rate depends on the temperature of the reactor: thermophilic reactors in general provide the highest biogas yields, whereas psychrophilic reactors are seen as less promising [40]. Despite this, most commercial farm digesters are mesophilic reactors because they seem to be more stable than their thermophilic counterparts [41, 42].

When considering plant sizes, it has been mentioned in literature that a methane yield of around $1m^3$ per m^3 of reactor volume per day can be achieved when using common technology such as stirring reactors. For typical livestock dairy management, around 100l of sludge per head can be expected [41, 43], and it can be calculated that seven cows produce the equivalent of biogas to operate an engine of $1kW_e$ power [39, 41, 44].

2.2.2 Fermentation

Fermentation processes convert biomass into Ethanol (EtOH) and consist of two consecutive steps: first, biomass starch is converted to sugars using enzymes, afterwards the sugars are fermented to EtOH using yeasts. The solid residues of fermentation, which still contain considerable amounts of biomass, can then be used for combustion or gasification. The water-diluted alcohol, containing around 10-15% EtOH, needs to be distilled to higher concentrations before being usable as fuel [10]. Typically, sugar cane and sugar beet are used for fermentation. Wood and plant wastes can theoretically also be fermented, although present technology is still in the prototype phase [10, 45, 46].

EtOH as the final fermentation product allows easier handling and storage when compared to gases, but due to the intensive feedstock pre-treatment, the necessary temperatures and the diluted intermediate product, the fermentation process is more complex than anaerobic digestion. Furthermore, methane as the main product of AD is rated as the ideal fuel because it is a comparatively clean fuel and a broad range of methane-based engines for heat and electricity generation are available [36]. Thus, despite the given advantages of storage and transport, fermentation processes are in general less suitable for micro-scale energy production than gas producing technologies.

2.2.3 Biochemical Conversion Technology Ranking

As for the thermochemical conversion technologies, a ranking of the applicability of biochemical conversion technologies for small scales is shown in Table II. Again, assessments vary from '---' for 'very poor' to '+++' for 'very good'.

As a result, AD seems more promising and viable for micro-scale applications, especially due to its simplicity and lower plant cost.

Table II: Ranking of biochemical conversion technologies

	AD	Fermentation
conversion level	++	++
simplicity	+++	---
plant cost	+++	--
conversion time	+	++
applicability to scale	+++	-

3 GENERATION TECHNOLOGIES

A biomass-driven generation plant can supply electricity and/or heat, the latter normally in the form of hot water of around 70-90°C. Alternatively, heat can be supplied in the form of steam or hot exhaust gas, or it can be applied to the processes e.g. for drying or preheating. Thus more intermediate fuel can be produced and stored to enhance the total process efficiency.

This chapter covers the main ways of converting the fuel into electrical energy: the first part describes heat-driven applications running on raw biomass feedstock, and the second part describes technology based on the use of liquid and gaseous fuels.

3.1 Heat-Driven Generation

Heat-driven generators produce shaft motion by using raw biomass feedstock and thus do not employ any conversion technologies. The feedstock is directly converted into heat by combustion, a process that generates temperatures of around 800-1000°C [10]. This heat is then used to run the engine. In general, combustion processes are very simple to set up, however they suffer from relatively low efficiencies of around 10-25% [47, 48]. The process is inherently slow and needs significant time to respond. Two main technologies running on combustion heat have been widely acknowledged in literature: Stirling engines and Externally Fired Microturbines.

3.1.1 Stirling Engines

Stirling engines are designed to use a cycle of heating and cooling a working gas; the gas is compressed, heated and expanded and then it is cooled. Due to the expansion it produces work at a piston. The net work produced is thus the piston work minus the work needed to compress the gas. A generator unit then converts the piston motion into electricity. Exhaust heat can be used for hot water in combined heat and power (CHP) applications using heat exchangers. Similarly, heat exchangers are also employed to transmit the combustion heat to the gas in the heating zone and to cool the gas in the cooling zone. [49]

In general, the working gas used in stirling engines is helium or hydrogen [49, 50], or compressed air due to its better availability [51]. The output power of stirling engines depends on the working gas pressure and on the temperature difference between the hot and cold zone [50, 52].

A number of stirling engines have been designed, tested and applied [17, 50, 51, 53-56]. However, their electrical efficiency has been rated as rather low and in the range of 20-25% [51, 52, 57, 58]. Also, since they are based on a continuous combustion process, most stirling engines are designed for steady state operation in base-load and heat-driven operation [59]. Part-load operation seems difficult and results in significantly lower efficiencies [60].

One of the main advantages of stirling engines is their fuel flexibility. All biomass suitable for combustion can be used to generate heat. Given the large range of commercial combustion grate and furnace technology, basically all feedstock is suitable. Since they use indirect heating, dirty feedstock can be used because apart from heat exchanger issues, tars are not an operation constraint due to having no direct engine contact. Additionally, most stirling engines can continuously run for long periods of time because their moving parts do not come in direct contact with the fuel. Operation cycles of 8,000-10,000hrs are common [17, 55], so the engines are well-suited for remote locations with a constant need of electricity, however, they are still regarded as less mature than other generation technology [33].

3.1.2 Externally Fired Microturbines

Microturbines are gas turbines for a power range of less than $500kW_e$. Although most turbines employ combustion chambers and expand the combustion air to generate shaft motion, some designs use heat exchanger technology similar to the stirling heat exchangers to heat the turbine working gas. In this case, the process is called Externally Fired Gas Turbine (EFGT) and the engine can be operated based on all combustion fuels, similar to the stirling technology.

In EFGT applications, biomass feedstock combustion provides the heat to be transmitted to compressed air used in the turbine. A high temperature heat exchanger, fired by a combustion furnace or grate, is employed to heat precompressed air. This hot air is then continuously expanded in the turbine and a generator, mounted on the turbine shaft, generates power. The expanded hot air at the turbine outlet can be used in CHP applications or within the process [61].

Due to material constraints and limits, the heat exchanger temperature limit is around 900-1100°C. Therefore the temperature limit of the compressed hot air to be expanded in the turbine is around 800-900°C [61-

63]. Compared to a common combustion chamber-fired microturbine which directly uses the combustion flue gas of 900-1100°C, a lower level of work and thus efficiency can be achieved. Levels of 20-25% were reported for the comparably low number of EFGT plants in operation [58].

When considering load flexibility, a test study revealed that although fast load changes can be applied by using a heat exchanger air bypass valve to rapidly lower the temperature of the working air volume, this results in very poor part-load efficiencies. Instead, variable speed operation caused by adjusting the amount of air being expanded in the turbine has been found as the best operation mode under part-load [64]. However, it has been mentioned that due to the steady combustion process being uncoupled from the turbine operation, the externally fired gas turbine is less able to cope with fast load changes [65]. Finally, the high temperature heat exchanger requires special materials due to the high temperature differences on both sides of the exchanger surface as well as corrosive combustion flue gases [66].

3.2 Fuel-Driven Generation

In contrast to the combustion-heat based generation engines, both microturbines and reciprocating engines can directly run on biogas, producer gas or liquid fuels such as ethanol or bio-oil. There are, however, significant difficulties when running microturbines on bio-oil due to the corrosivity of the fuel [33].

3.2.1 Microturbines

Microturbines (MT) are small, predominantly aeroderivative turbines using a comparably simple design and a generator directly mounted on the turbine shaft [67, 68]. Air is compressed, heated and then expanded in the turbine to produce motion. A recuperator can be used to preheat the compressed air with the exhaust gas heat before entering the combustion chamber. This increases the turbine efficiency by around 5%, however the turbine exhaust gas temperature is lowered from around 600°C in simple cycles to around 300°C in recuperative cycles and there is a significant cost impact [58, 69-71].

A number of suppliers have designed turbines down to 30kW$_e$ [67, 68, 72, 73], in both CHP and power-only applications. The further design provides hot water of around 70-90°C, whereas the latter provide an exhaust gas stream of high temperature.

One of the advantages of microturbines over internal combustion engines is their high exhaust gas temperature and therefore the possibility to use this heat within the process [7, 58]. Microturbines can also be run on fuels with varying calorific values, and special designs for compressed low-calorific biogas or producer gas are available [74, 75].

Another major advantage is their low maintenance need. Microturbines use air bearings and single shaft technology, and together with a smooth rotation of the turbine, very long maintenance cycles of up to 10,000-15,000hrs of continuous operation can be achieved [67, 73, 76-78].

Finally, due to their constant combustion, emission levels are far below those of reciprocating engines [79-81], and given their price range of around 1000-1900€/kW$_e$ [69, 74, 82] they are a promising alternative to reciprocating engines.

In terms of fuel efficiency, microturbines employing recuperative cycles result in efficiencies of around 25-35%, which is around 5% less than reciprocating engines [7, 58, 83], and they have a comparably robust efficiency behaviour under part-load, albeit also slightly below that of reciprocating engines [77, 79, 83, 84]

Microturbines can be operated comparably easily: by regulating the amount of fuel and/or air input, the power output can be adjusted. Two operation modes have been discussed in literature: constant speed/variable temperature mode, where the air mass flow is kept steady and the combustion temperature is regulated, and variable speed/constant temperature mode, where the air mass flow is adjusted, but the combustion temperature is kept steady. A number of tests have shown that the variable speed mode achieves significantly better part-load efficiencies [79, 83, 85], so although a more advanced alternator is needed due to the varying revolution speed, variable speed operation can be applied to better accommodate rapid and frequent load changes.

A number of tests were performed to investigate the transient behaviour of microturbines [70, 71, 86]. A microturbine can be started within around 5min from cold start and around 2min from warm start, and after around 1min the electricity supply begins. Shutdowns of the turbine result in a stop of power export after around 30s.

When applying load changes, ramping times of around 15-20s between two power output levels were achieved in grid-connected mode, and slightly better results have been found for stand-alone tests by using on-board batteries to immediately cover the transient period and to provide the startup power.

As a summary, microturbines are considered suitable for single power source microgrids being able to cope with fluctuating loads.

3.2.2 Gas Engines and Internal Combustion Engines

Gas engines can be defined as Internal Combustion Engines (ICE) running on gases such as natural gas, producer gas or biogas. Most gas engines are spark ignition engines, whereas ICE can be either compression ignition or spark ignition engines, however, most ICE can also be converted to run on gas.

Gas engines and ICE have been in commercial operation for decades, in units ranging from a few kW$_e$ up to several MW$_e$, and with price ranges of around 500-1000€/kW$_e$ [45, 77, 82, 87, 88]. Gas engines are described as robust against fuel quality changes [89], however their exhaust gas temperature is rather low with around 80-100°C [7, 82], which makes further usage of it difficult.

Gas engine efficiency lies in the range of 30-40% [7, 57, 58, 82] with a decrease under part-load operation similar to microturbines [90].

One problem in using bio-derived fuels is that, due to that H_2S as a by-product of AD is highly soluble in oil lubricants, frequent lubrication changes are necessary and maintenance cycles (oil and filter changes) can be as frequent as every 500hrs [16, 20, 77, 78, 91]. This effect highly reduces the applicability of those engines in rural and remote areas, especially when they are intended to run as the single generation unit and no skilled personnel is at hand [16, 78].

Finally, reciprocating engine emission levels, especially in terms of CO and NO_x, are significantly higher than those of other generators. Differences of up to an order of magnitude were reported [80, 81, 84], and especially when running on biomass fuels, it has to be taken into consideration whether high amounts of emissions from reciprocating engines are acceptable.

In terms of flexibility of operation, reciprocating engines again perform better than other generation technologies. Reasonable load changes can be adopted very quickly, and the suitability for fluctuating loads is high, hence they were the standard solution for emergency gensets. However, microturbines with battery packs are increasingly replacing diesel emergency gensets due to their better maintenance behaviour [72, 73, 78].

3.3 Generation Technology Ranking

The following table summarises the technical and operational behavior of the generation technologies discussed earlier and ranks them based on their applicability for the desired micro-scale applications. Again, assessments vary from '---' for 'very poor' to '+++' for 'very good'.

Table III: Ranking of generation technologies

	Stirling	EFGT	MT	ICE
full efficiency	--	--	+	+++
part efficiency	--	--	+	+++
load flexibility	-	-	++	++
investment cost	---	--	-	+++
maintenance	++	++	+++	---
emissions	++	++	+++	---
development level	+	++	++	+++

It is concluded that, despite their higher investment cost, microturbines seem a better alternative for providing energy to remote customers, especially in remote areas where maintenance and operation ease are of key importance. Additionally, the comparably high load flexibility of microturbines should provide strong incentives, and when the market for microturbines starts to maturise, decreasing price differences between microturbines and ICEs can be expected, which will further promote the employment of this technology.

4 COMBINED PLANT DESIGN PROPOSAL

From the above, it can be concluded that gasification and anaerobic digestion seem probable for the intended scale of 5-50kW$_e$. When considering remote farms as a major target group, they can provide considerable amounts of organic waste which can be used as biomass feedstock.

Given that a farm typically has both livestock management and plant cultivation, both wet and dry biomass will be available. Thus it will be worth examining ways to use both feedstocks by combining thermochemical and biochemical treatment.

A plant consisting of a co-current fixed-bed gasifier and a thermophilic anaerobic digester is considered to be the best solution to provide both efficient waste management systems and the production of considerable amounts of biogas and producer gas. This fuel can then be used in a microturbine to provide both electricity and heat. It also offers the advantages of long maintenance cycles and good response to load changes. Lastly, a microturbine can be operated autonomously by remote or preset control and thus the absence of skilled personnel on site will not be an issue.

The proposed plant will be required to instantaneously cover the electrical load demand of the customer, which will consist of electricity needs for farm houses and adjacent buildings. As a result, a highly transient and fluctuating load demand curve is expected.

Existing plants are designed to operate as base load applications, and the grid connection is used to import any extra energy used. Common stand-alone or island applications employ batteries to instantly cover the load change and to allow sufficient time to change the generation output of the engine. However, batteries as well as other electricity storages result in maintenance efforts and losses.

Instead of trying to mirror the load demand with the generation output and covering the transition interval with electricity storage, our proposed plant will be designed to run on a comparably steady load. This normally results in a surplus of electricity generation, so an electricity sink in the form of an electric feedstock heater will be activated. This will result in better conversion efficiencies due to drier feedstock, and thus more intermediate fuel gas will be produced. This gas can then be stored more efficiently than the electricity surplus.

In terms of the customer heat demands, it has been found that in general they are significantly lower than the process heat output from the unit. Unfortunately, times of high electricity demand do not always cohere with times of high heat demand and thus not all heat can be used by the customer. Therefore, the proposal aims for a high level of internal usage of the process heat.

Figure 1 shows a flow chart of the desired plant, and the main parts are described in the following sections.

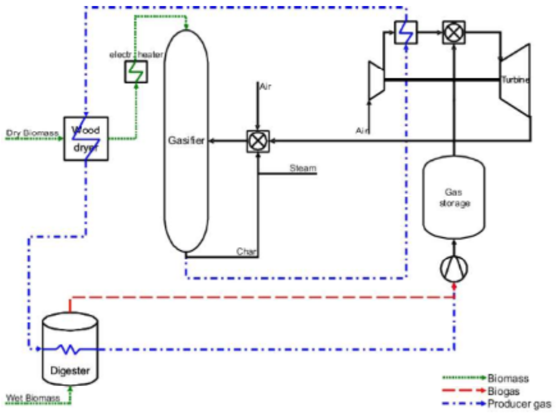

Figure 1: Combined Plant Design Flowchart

4.1 Generation unit (Microturbine)

The generator is a microturbine compressing air of ambient temperature. A heat exchanger will be employed to use the thermal energy of the producer gas and to preheat the compressed air before it enters the combustion chamber. There, air and fuel gas released from the storage system will be mixed and burnt. Since a pressurised gas storage is used, the fuel gas does not need to be compressed before it enters the combustion chamber. The high turbine exhaust gas temperature will be used within the gasification unit as described below.

The turbine will be in the size of 30-50kW$_e$ and it will be operated on variable speed mode between half- and full load. As mentioned earlier, the time interval needed to change the turbine speed and thus the electrical output is in the range of several seconds. The turbine operation will be comparably steady, and load steps following the time of day will be used in a way that it is always secured that the turbine produces at least the load demanded by the customer.

The gas needed to run the turbine will be a mixture of producer gas and biogas, as shown in figure 1. This results in a higher calorific value compared to running the turbine on producer gas alone, and the two gases can be stored in the same storage system. Turbine operation on varying calorific values has been proven to be possible and stable, so variations in the ratio of biogas and producer gas should not be a critical topic.

4.2 Gasification unit

A simple fixed bed co-current gasifier is used to process crop wood and other suitable dry farm waste to generate producer gas. After being shredded to the right particle size, the feedstock stream will be dried in the wood dryer, further using the heat of exiting producer gas.

The co-current reactor design has been proven to be usable with varying biomass feedstock moisture contents, so the unsteady activation of the electric heater will positively affect the gasification yield without detrimentally affecting its steady-state operation in times of high electricity demand. Part of the dried biomass feedstock and unconverted biomass char can be burnt in the combustion chamber to provide sufficient heat levels for a continuous high temperature gasification agent stream. The hot producer gas will then be used to preheat the compressed turbine air, followed by drying the biomass feedstock in the wood dryer. After those two heating cycles, the producer gas will have a relatively low temperature, however it can still provide sufficient heat for the digestion unit.

4.3 Anaerobic Digestion unit

The anaerobic digestion unit of the plant will process highly diluted farm waste such as manure or food and vegetable waste. A simple plug-flow or steady-flow thermophilic digester design will be employed to ensure low design cost and the highest gas yields for the comparably uniform feedstock flow.

The sizes of the anaerobic digestion and gasification reactors will be chosen depending on the amount of livestock and suitable dry feedstock material available on site. It must be of a suitable size such that enough biogas and producer gas are produced to continuously be able to meet the customer power demand.

4.4 Gas storage system

The gas storage system will play a key role within the plant. It will be the main energy storage system and will be sufficient in size to be able to completely cover the peak load demand.

Both the biogas and the producer gas are compressed to a pressure level sufficient to be able to operate the microturbine on the gas mixture. Both gases are stored in one pressurised tank. This enables a mixing of the two gas streams and thus results in a more balanced calorific value of the gas mixture.

5 CONCLUSION AND OUTLINE OF FUTURE WORK

For a micro-scale biomass unit, a fixed-bed gasification reactor coupled with simple anaerobic digestion tanks offers a viable combined plant solution. In terms of generation equipment, microturbines show many advantages over conventional internal combustion engines with regards to maintenance and flexibility.

The plant design described in this paper is able to autonomously cover the electrical demand of a remote customer providing sufficient amounts of biomass waste. A design consisting of both wet and dry feedstock processing and a flexibly-running microturbine can support or even replace a weak grid connection. Although the project of developing such a plant is still in an early stage, it is a very promising alternative for rural areas.

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Appendix B – Plant Model

The following pages provide the Aspen Plus programming source code for the plant model developed and described in chapter 5. Using this code, the plant model can be rebuilt for further analyses.

♀

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          + + +   + + +   + + +   + + +   + + +   + + +   + + +
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            +     + + +   + + +   + + +   + + +   + + +     +
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                  + + +   + + +   + + +   + + +   + + +
                    +       +     + + +     +       +
                                  + + +
                                  + + +
                                  + + +
ASPENTECH                         + + +
                                  + + +
FLOWSHEET SIMULATION              + + +
FOR THE PROCESS INDUSTRIES        + + +
                                    +


                                                                       TM
AAAAA   SSSSS   PPPPP   EEEEE   NN    N   PPPPP   L       U   U   SSSSS
A   A   S       P   P   E       N N   N   P   P   L       U   U   S
AAAAA   SSSSS   PPPPP   EEEEE   N   N N   PPPPP   L       U   U   SSSSS
A   A       S   P       E       N    NN   P       L       U   U       S
A   A   SSSSS   P       EEEEE   N     N   P       LLLLL   UUUUU   SSSSS
```

ASPEN PLUS IS A TRADEMARK OF
ASPEN TECHNOLOGY, INC.
TEN CANAL PARK
CAMBRIDGE, MASSACHUSETTS 02141
617/949-1000

HOTLINE:
U.S.A. 888/996-7100
EUROPE (32) 2/701-9555

PLATFORM: WIN32
VERSION: 21.0   Build 52
INSTALLATION:

MAY 8, 2009
FRIDAY
9:19:18 A.M.

THIS COPY OF ASPEN PLUS LICENSED TO UNIV OF BATH

♀

*** INPUT SUMMARY ***

>>CURRENT RUN

```
  ORIGINAL RUN                           MAY 8, 2009
  9:19:18 A.M.                           FRIDAY
  INPUT FILE: _2750jmo.inm
  RUN ID : _2750jmo
    ;
    ;Input file created by Aspen Plus Rel. 21.0 at 09:19:17 Fri May 8, 2009
    ;Directory H:\Aspen Simulations\Final\  Runid v31
    ;


    DYNAMICS
        DYNAMICS RESULTS=ON

    IN-UNITS SI MASS-FLOW='kg/hr' MOLE-FLOW='kmol/hr'  &
```

```
        VOLUME-FLOW='cum/hr' PRESSURE=bar TEMPERATURE=C DELTA-T=C  &
        PDROP-PER-HT='mbar/m' PDROP=bar

DEF-STREAMS CONVEN ALL

DESCRIPTION "
    General Simulation with Metric Units :
    C, bar, kg/hr, kmol/hr, Gcal/hr, cum/hr.

    Property Method: None

    Flow basis for input: Mole

    Stream report composition: Mole flow
    "

DATABANKS PURE13  / AQUEOUS  / SOLIDS  / INORGANIC  /  &
        NOASPENPCD

PROP-SOURCES PURE13  / AQUEOUS  / SOLIDS  / INORGANIC

COMPONENTS
    BIOMASS /
    ASH /
    H2O H2O /
    O2 O2 /
    N2 N2 /
    CO CO /
    CO2 CO2 /
    H2 H2 /
    CH4 CH4 /
    C C /
    S S /
    NO NO /
    SO2 O2S /
    H2S H2S /
    NH3 H3N /
    N2O N2O /
    C2H6 C2H6 /
    SOLIDS

ADA-SETUP
    ADA-SETUP PROCEDURE=REL9

FLOWSHEET
    BLOCK AD-HE IN=PRODGAS2 MAN-INL OUT=PRODGAS3 INLETHOT
    BLOCK DECOMP IN=BIOMSS-D OUT=ELEMENTS QDECOMP
    BLOCK GASIFIER IN=ELEMENTS H-AIR QDECOMP OUT=PRODGCH
    BLOCK GF-SEPAR IN=PRODGCH OUT=CHAR PRODGAS
    BLOCK AIRCOMP IN=AIR-IN OUT=CMP-AIR W-IN
    BLOCK TURB IN=TURB-INL OUT=EXHAUST W-SHAFT
    BLOCK TURB-CCH IN=CMP-HAIR GAS2TURB OUT=TURB-INL
    BLOCK TURB-HEX IN=PRODGAS CMP-AIR OUT=PRODGAS2 CMP-HAIR
    BLOCK AD-SEPAR IN=OUTLET OUT=SLURRY BIOGAS
    BLOCK STOREMIX IN=PRODGAS4 BIOGAS OUT=MIXGAS
    BLOCK STORECMP IN=MIXGAS OUT=COMPGAS W-IN2
    BLOCK DIGESTER IN=INLETHOT OUT=OUTLET
    BLOCK GASIF-HE IN=EXHAUST AIR OUT=EXHAUST2 H-AIR
    BLOCK CMPSPLIT IN=COMPGAS OUT=GAS2TURB GAS2STOR
    BLOCK DRY-REAC IN=EXHAUST2 BIOMSSIN OUT=TO-SEP
    BLOCK ELECREAC IN=BIOMSS-W OUT=TO-SEP2
    BLOCK AD-HLOSS IN=PRODGAS3 OUT=PRODGAS4
    BLOCK DRY-SEP IN=TO-SEP OUT=EXHAUST3 BIOMSS-W
    BLOCK ELEC-SEP IN=TO-SEP2 OUT=BIOMSS-D ELVAPOR

PROPERTIES IDEAL

NC-COMPS BIOMASS PROXANAL ULTANAL SULFANAL

NC-PROPS BIOMASS ENTHALPY HCOALGEN / DENSITY DCOALIGT

NC-COMPS ASH PROXANAL ULTANAL SULFANAL

NC-PROPS ASH ENTHALPY HCOALGEN / DENSITY DCOALIGT

NC-COMPS SOLIDS GENANAL

NC-PROPS SOLIDS ENTHALPY ENTHGEN / DENSITY DNSTYGEN

PROP-DATA NC-1
    IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
        HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
        VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
        MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
        MASS-ENTHALP='kcal/kg' MASS-HEAT-CA='kJ/kg-K' HEAT=Gcal  &
        MOLE-CONC='mol/l' PDROP=bar
    PROP-LIST HCGEN
```

```
        PVAL SOLIDS 4.183

    PROP-DATA NC-1
        IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
            HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
            VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
            MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
            MASS-ENTHALP='kJ/kg' HEAT=Gcal MOLE-CONC='mol/l' PDROP=bar
        PROP-LIST DHFGEN
        PVAL SOLIDS 230.

    PROP-DATA NC-1
        IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
            HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
            VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
            MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
            MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-CONC='mol/l'  &
            PDROP=bar
        PROP-LIST DENGEN
        PVAL SOLIDS 105.

    DEF-SUBS-ATTR PSD PSD
        IN-UNITS ENG
        INTERVALS 10
        SIZE-LIMITS 0.0 <mm> / 2. <mm> / 4. <mm> / 6. <mm> /  &
            8. <mm> / 10. <mm> / 12. <mm> / 14. <mm> / 16. <mm> /  &
            18. <mm> / 20. <mm>

    DEF-STREAM-C CONVEN MIXED NC

    DEF-STREAMS MCINCPSD INLETHOT AIR AIR-IN BIOMSS-D CHAR  &
            ELEMENTS EXHAUST PRODGAS CMP-AIR MAN-INL OUTLET PRODGCH  &
            CMP-HAIR PRODGAS2 PRODGAS4 BIOGAS SLURRY COMPGAS MIXGAS  &
            TURB-INL EXHAUST2 H-AIR GAS2STOR GAS2TURB BIOMSS-W  &
            TO-SEP EXHAUST3 BIOMSSIN ELVAPOR TO-SEP2 PRODGAS3

    STREAM AIR
        SUBSTREAM MIXED TEMP=25. PRES=1. MASS-FLOW=81.2
        STDVOL-FRAC O2 0.21 / N2 0.79

    STREAM AIR-IN
        SUBSTREAM MIXED TEMP=25. PRES=1. MASS-FLOW=125.
        STDVOL-FRAC O2 0.21 / N2 0.79

    STREAM BIOMSSIN
        SUBSTREAM NCPSD TEMP=25. PRES=1.
        MASS-FLOW BIOMASS 112.5
        COMP-ATTR BIOMASS PROXANAL ( 60. 17.2 81.28 1.52 )
        COMP-ATTR BIOMASS ULTANAL ( 1.52 49.48 5.38 0.35 0.  &
            0.01 43.26 )
        COMP-ATTR BIOMASS SULFANAL ( 0. 0. 0.01 )
        SUBS-ATTR PSD ( 0 0 0 0 0.1 0.2 0.3 0.4 )

    STREAM MAN-INL
        IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
            HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
            VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
            MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
            MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-CONC='mol/l'  &
            PDROP=bar
        SUBSTREAM MIXED TEMP=20. PRES=1. MASS-FLOW=9900. <kg/day>
        MASS-FRAC H2O 1.
        SUBSTREAM NCPSD TEMP=20. PRES=1. MASS-FLOW=1100. <kg/day>
        MASS-FRAC SOLIDS 1.
        COMP-ATTR SOLIDS GENANAL ( 100. )
        SUBS-ATTR PSD ( 0 0.1 0.2 0.3 0.4 0 0 0 0 0 0. )

    DEF-STREAMS HEAT QDECOMP

    DEF-STREAMS WORK W-IN

    DEF-STREAMS WORK W-IN2

    DEF-STREAMS WORK W-SHAFT

    BLOCK STOREMIX MIXER
        PARAM PRES=1.

    BLOCK CMPSPLIT FSPLIT
        FRAC GAS2TURB 1.

    BLOCK AD-SEPAR SEP
        PARAM
        FRAC STREAM=SLURRY SUBSTREAM=CIPSD COMPS=C FRACS=1.
        FRAC STREAM=SLURRY SUBSTREAM=NCPSD COMPS=BIOMASS ASH  &
            SOLIDS FRACS=1. 1. 1.
        MASS-FLOW STREAM=BIOGAS SUBSTREAM=MIXED COMPS=H2O FLOWS= &
```

```
        5.

BLOCK DRY-SEP SEP
    PARAM
    FRAC STREAM=EXHAUST3 SUBSTREAM=MIXED COMPS=H2O O2 N2 CO  &
        CO2 H2 CH4 C S NO SO2 H2S NH3 N2O C2H6 FRACS=1.  &
        1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1.
    FRAC STREAM=EXHAUST3 SUBSTREAM=NCPSD COMPS=BIOMASS ASH  &
        SOLIDS FRACS=0. 0. 0.
    FRAC STREAM=BIOMSS-W SUBSTREAM=CIPSD COMPS=C FRACS=1.

BLOCK ELEC-SEP SEP
    FRAC STREAM=BIOMSS-D SUBSTREAM=MIXED COMPS=H2O FRACS=0.
    FRAC STREAM=BIOMSS-D SUBSTREAM=CIPSD COMPS=C FRACS=1.
    FRAC STREAM=BIOMSS-D SUBSTREAM=NCPSD COMPS=BIOMASS ASH  &
        SOLIDS FRACS=1. 1. 1.
    FLASH-SPECS BIOMSS-D TEMP=200.

BLOCK GF-SEPAR SEP
    PARAM
    FRAC STREAM=CHAR SUBSTREAM=CIPSD COMPS=C FRACS=1.
    FRAC STREAM=CHAR SUBSTREAM=NCPSD COMPS=BIOMASS ASH FRACS= &
        1. 1.
    FRAC STREAM=PRODGAS SUBSTREAM=MIXED COMPS=H2O O2 N2 CO  &
        CO2 H2 CH4 C S NO SO2 H2S NH3 N2O C2H6 FRACS=1.  &
        1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1. 1.

BLOCK AD-HLOSS HEATER
    PARAM PRES=1. DUTY=-10000.

BLOCK AD-HE HEATX
    IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
        HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
        VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
        MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
        MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-CONC='mol/l'  &
        PDROP=bar
    PARAM T-COLD=35. CALC-TYPE=DESIGN U-OPTION=PHASE  &
        F-OPTION=CONSTANT CALC-METHOD=SHORTCUT
    FEEDS HOT=PRODGAS2 COLD=MAN-INL
    PRODUCTS HOT=PRODGAS3 COLD=INLETHOT
    EQUIP-SPECS
    TUBES INSIDE-DIAM=0.5 <meter> WALL-THICK=0.01 <meter>
    HOT-SIDE DP-OPTION=CONSTANT
    COLD-SIDE DP-OPTION=CONSTANT

BLOCK GASIF-HE HEATX
    PARAM DELT-COLD=10. <K> U-OPTION=PHASE F-OPTION=CONSTANT  &
        CALC-METHOD=SHORTCUT
    FEEDS HOT=EXHAUST COLD=AIR
    PRODUCTS HOT=EXHAUST2 COLD=H-AIR
    HOT-SIDE DP-OPTION=CONSTANT
    COLD-SIDE DP-OPTION=CONSTANT

BLOCK TURB-HEX HEATX
    PARAM CALC-TYPE=SIMULATION P-UPDATE=YES U-OPTION=FILM-COEF  &
        F-OPTION=GEOMETRY CALC-METHOD=DETAILED
    FEEDS HOT=PRODGAS COLD=CMP-AIR
    PRODUCTS HOT=PRODGAS2 COLD=CMP-HAIR
    EQUIP-SPECS SHELL-DIAM=0.24
    TUBES TOTAL-NUMBER=17 PATTERN=TRIANGLE LENGTH=2.  &
        INSIDE-DIAM=0.038 OUTSIDE-DIAM=0.039 PITCH=0.053625
    NOZZLES SNOZ-INDIAM=0.1 SNOZ-OUTDIAM=0.1 TNOZ-INDIAM=0.1  &
        TNOZ-OUTDIAM=0.1
    SEGB-SHELL NBAFFLE=3 BAFFLE-CUT=0.3 MID-BFL-SP=0.5  &
        IN-BFL-SP=0.5
    HOT-SIDE H-OPTION=GEOMETRY SHELL-TUBE=TUBE DP-OPTION=GEOMETRY
    COLD-SIDE H-OPTION=GEOMETRY DP-OPTION=GEOMETRY

BLOCK DRY-REAC RSTOIC
    PARAM PRES=1. DUTY=0.
    STOIC 1 NCPSD BIOMASS -1. / MIXED H2O 0.0555084
    CONV 1 NCPSD BIOMASS 0.1
    COMP-ATTR NCPSD BIOMASS PROXANAL ( 10. )

BLOCK ELECREAC RSTOIC
    PARAM PRES=1. DUTY=5000.
    STOIC 1 NCPSD BIOMASS -1. / MIXED H2O 0.0555084
    CONV 1 NCPSD BIOMASS 0.2
    COMP-ATTR NCPSD BIOMASS PROXANAL ( 40. )

BLOCK DECOMP RYIELD
    PARAM TEMP=25. PRES=1.
    MASS-YIELD MIXED H2O 0.2 / NCPSD ASH 0.1 / CIPSD C  &
        0.2 / MIXED H2 0.2 / N2 0.1 / S 0.1 / O2 0.1
    COMP-ATTR NCPSD ASH PROXANAL ( 0. 0. 0. 100. )
    COMP-ATTR NCPSD ASH ULTANAL ( 100. 0. 0. 0. 0. 0. 0.  &
```

```
        )
    COMP-ATTR NCPSD ASH SULFANAL ( 0. 0. 0. )

BLOCK DIGESTER RYIELD
    PARAM TEMP=35. PRES=1.
    MASS-YIELD MIXED H2O 0.9 / NCPSD SOLIDS 0.04 / MIXED  &
        CO2 0.03 / CH4 0.03

BLOCK GASIFIER RGIBBS
    PARAM PRES=1.
    PROD H2O / N2 / O2 / S / H2 / C S / CO / CO2 /  &
        NO / SO2 / H2S / NH3 / N2O / C2H6

BLOCK TURB-CCH RGIBBS
    PARAM TEMP=1000. PRES=5.
    PROD H2O / O2 / N2 / CO / CO2 / H2 / CH4 / NO /  &
        SO2 / H2S / NH3 / N2O / C2H6

BLOCK AIRCOMP COMPR
    PARAM TYPE=ISENTROPIC PRATIO=3.35 SEFF=0.74 MEFF=0.89

BLOCK STORECMP COMPR
    PARAM TYPE=ISENTROPIC PRATIO=5. SEFF=0.74 MEFF=0.89

BLOCK TURB COMPR
    PARAM TYPE=ISENTROPIC PRES=1. SEFF=0.86 MEFF=0.974 NPHASE=1  &
        MODEL-TYPE=TURBINE
    BLOCK-OPTION FREE-WATER=NO

DESIGN-SPEC LAMBDA
    DEFINE DUTY BLOCK-VAR BLOCK=TURB-CCH VARIABLE=QCALC  &
        SENTENCE=PARAM
    SPEC "DUTY" TO "0"
    TOL-SPEC "100"
    VARY STREAM-VAR STREAM=AIR-IN SUBSTREAM=MIXED  &
        VARIABLE=MOLE-FLOW
    LIMITS "10" "10000"

EO-CONV-OPTI

CALCULATOR AD
    IN-UNITS MET VOLUME-FLOW='cum/hr' ENTHALPY-FLO='Gcal/hr'  &
        HEAT-TRANS-C='kcal/hr-sqm-K' PRESSURE=bar TEMPERATURE=C  &
        VOLUME=cum DELTA-T=C HEAD=meter MOLE-DENSITY='kmol/cum'  &
        MASS-DENSITY='kg/cum' MOLE-ENTHALP='kcal/mol'  &
        MASS-ENTHALP='kcal/kg' HEAT=Gcal MOLE-CONC='mol/l'  &
        PDROP=bar
    DEFINE SLDIN MASS-FLOW STREAM=INLETHOT SUBSTREAM=NCPSD  &
        COMPONENT=SOLIDS
    DEFINE H2OIN MASS-FLOW STREAM=INLETHOT SUBSTREAM=MIXED  &
        COMPONENT=H2O
    DEFINE H2OOUT BLOCK-VAR BLOCK=DIGESTER VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=H2O
    DEFINE CH4OUT BLOCK-VAR BLOCK=DIGESTER VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=CH4
    DEFINE CO2OUT BLOCK-VAR BLOCK=DIGESTER VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=CO2
    DEFINE SLDOUT BLOCK-VAR BLOCK=DIGESTER VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=NCPSD ID2=SOLIDS

F      VSS = 0.75 * SLDIN
F      COD = 1.5 * VSS
F      CODREM = 0.6 * COD
F      CH4VOL = 0.2 * CODREM
F      CH4MAS = 0.717 * CH4VOL
F      CO2VOL = CH4VOL * 2 / 3
F      CO2MAS = 1.98 * CO2VOL
F      TOTAL = SLDIN + H2OIN
F      H2OOUT = H2OIN / TOTAL
F      CH4OUT = CH4MAS / TOTAL
F      CO2OUT = CO2MAS / TOTAL
F      SLDOUT = 1 - H2OOUT - CO2OUT - CH4OUT
    EXECUTE BEFORE BLOCK DIGESTER

CALCULATOR AD-HLOSS
    DEFINE H2OIN STREAM-VAR STREAM=MAN-INL SUBSTREAM=MIXED  &
        VARIABLE=MASS-FLOW
    DEFINE SLDIN STREAM-VAR STREAM=MAN-INL SUBSTREAM=NCPSD  &
        VARIABLE=MASS-FLOW
    DEFINE HLOSS BLOCK-VAR BLOCK=AD-HLOSS VARIABLE=DUTY  &
        SENTENCE=PARAM
F      MANIN = (H2OIN + SLDIN) * 24
F      VOL = (20 * MANIN) / 1000
F      PI   = ACOS(-1.0)
F      VOLPI = VOL / PI
F      RATIO = VOLPI ** (1./3.)
F      SURF = 4 * PI * (RATIO ** 2.0)
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F      HLOSS = -(35 * SURF)
    EXECUTE BEFORE BLOCK AD-HLOSS

CALCULATOR AD-SEPAR
    DEFINE H2OVAP BLOCK-VAR BLOCK=AD-SEPAR SENTENCE=MASS-FLOW  &
        VARIABLE=FLOWS ID1=MIXED ID2=BIOGAS ELEMENT=1
    DEFINE CH4CON MASS-FLOW STREAM=OUTLET SUBSTREAM=MIXED  &
        COMPONENT=CH4
    DEFINE CO2CON MASS-FLOW STREAM=OUTLET SUBSTREAM=MIXED  &
        COMPONENT=CO2
F       H2OVAP = (CO2CON + CH4CON) / 19
    EXECUTE BEFORE BLOCK AD-SEPAR

CALCULATOR DRYER
    DEFINE H2OIN COMP-ATTR-VAR STREAM=BIOMSSIN SUBSTREAM=NCPSD  &
        COMPONENT=BIOMASS ATTRIBUTE=PROXANAL ELEMENT=1
    DEFINE CONV BLOCK-VAR BLOCK=DRY-REAC VARIABLE=CONV  &
        SENTENCE=CONV ID1=1
    DEFINE H2ODRY BLOCK-VAR BLOCK=DRY-REAC VARIABLE=VALUE  &
        SENTENCE=COMP-ATTR ID1=1 ELEMENT=1
F      H2ODRY = 10
F      CONV = (H2OIN - H2ODRY) / (100 - H2ODRY)
    EXECUTE BEFORE BLOCK DRY-REAC

CALCULATOR ELDRYER
    DEFINE MSTIN COMP-ATTR-VAR STREAM=BIOMSS-W SUBSTREAM=NCPSD  &
        COMPONENT=BIOMASS ATTRIBUTE=PROXANAL ELEMENT=1
    DEFINE BIOMIN MASS-FLOW STREAM=BIOMSS-W SUBSTREAM=NCPSD  &
        COMPONENT=BIOMASS
    DEFINE DUTY BLOCK-VAR BLOCK=ELECREAC VARIABLE=DUTY  &
        SENTENCE=PARAM
    DEFINE CONV BLOCK-VAR BLOCK=ELECREAC VARIABLE=CONV  &
        SENTENCE=CONV ID1=1
    DEFINE H2OEVP MASS-FLOW STREAM=TO-SEP2 SUBSTREAM=MIXED  &
        COMPONENT=H2O
    DEFINE MSTOUT BLOCK-VAR BLOCK=ELECREAC VARIABLE=VALUE  &
        SENTENCE=COMP-ATTR ID1=1 ELEMENT=1
F      H2OIN = (BIOMIN / 3600) * (MSTIN / 100)
F      H2OEVP = (DUTY / 5000000) * 3600
F      CONV = H2OEVP / BIOMIN
F      BIOMD = ((100 - MSTIN) / 100) * BIOMIN
F      H2OEX = ((MSTIN / 100) * BIOMIN) - H2OEVP
F      MSTOUT = (H2OEX / (BIOMD + H2OEX)) * 100
    EXECUTE BEFORE BLOCK ELECREAC

CALCULATOR GASAIR
    DEFINE MBIOM MASS-FLOW STREAM=BIOMSS-D SUBSTREAM=NCPSD  &
        COMPONENT=BIOMASS
    DEFINE MASH MASS-FLOW STREAM=ELEMENTS SUBSTREAM=NCPSD  &
        COMPONENT=ASH
    DEFINE MH2O MASS-FLOW STREAM=ELEMENTS SUBSTREAM=MIXED  &
        COMPONENT=H2O
    DEFINE MAIR STREAM-VAR STREAM=AIR SUBSTREAM=MIXED  &
        VARIABLE=MASS-FLOW
F   MAIR = 1.5 * (MBIOM - MASH - MH2O)
    EXECUTE BEFORE BLOCK GASIFIER

CALCULATOR GASIFIER
    VECTOR-DEF ULT COMP-ATTR STREAM=BIOMSS-D SUBSTREAM=NCPSD  &
        COMPONENT=BIOMASS ATTRIBUTE=ULTANAL
    DEFINE WATER COMP-ATTR-VAR STREAM=BIOMSS-D SUBSTREAM=NCPSD  &
        COMPONENT=BIOMASS ATTRIBUTE=PROXANAL ELEMENT=1
    DEFINE H2O BLOCK-VAR BLOCK=DECOMP VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=H2O
    DEFINE ASH BLOCK-VAR BLOCK=DECOMP VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=NCPSD ID2=ASH
    DEFINE CARB BLOCK-VAR BLOCK=DECOMP VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=CIPSD ID2=C
    DEFINE H2 BLOCK-VAR BLOCK=DECOMP VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=H2
    DEFINE N2 BLOCK-VAR BLOCK=DECOMP VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=N2
    DEFINE SULF BLOCK-VAR BLOCK=DECOMP VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=S
    DEFINE O2 BLOCK-VAR BLOCK=DECOMP VARIABLE=YIELD  &
        SENTENCE=MASS-YIELD ID1=MIXED ID2=O2
    DEFINE INTEMP STREAM-VAR STREAM=BIOMSS-D SUBSTREAM=NCPSD  &
        VARIABLE=TEMP
    DEFINE RETEMP BLOCK-VAR BLOCK=DECOMP VARIABLE=TEMP  &
        SENTENCE=PARAM
F      FACT = (100 - WATER) / 100
F      H2O  = WATER / 100
F      ASH  = ULT(1) / 100 * FACT
F      CARB = ULT(2) / 100 * FACT
F      H2   = ULT(3) / 100 * FACT
F      N2   = ULT(4) / 100 * FACT
F      SULF = ULT(6) / 100 * FACT
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F      O2   = ULT(7) / 100 * FACT
F      RETEMP = INTEMP
    EXECUTE BEFORE BLOCK DECOMP

CALCULATOR STORERAT
    DEFINE RATIO BLOCK-VAR BLOCK=CMPSPLIT SENTENCE=FRAC  &
        VARIABLE=FRAC ID1=GAS2TURB
F      RATIO = 1
    EXECUTE BEFORE BLOCK TURB-CCH

STREAM-REPOR NOSORT MOLEFLOW MASSFLOW MOLEFRAC MASSFRAC

PROPERTY-REP PCES

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